Independent Engineer's Report for the Gainesville Renewable Energy Center

Gainesville Regional Utilities

GREC Independent Engineer's Report
Project No. 101300

8/11/2017

Independent Engineer's Report for the Gainesville Renewable Energy Center

prepared for

Gainesville Regional Utilities
GREC Independent Engineer's Report
Gainesville, Florida

Project No. 101300

8/11/2017

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

TABLE OF CONTENTS

Page No.

LIST OF TABLES

Page No.

LIST OF FIGURES

Page No.

LIST OF ABBREVIATIONS

Abbreviation	**Term/Phrase/Name**
ACEPD	Alachua County Environmental Protection Division
AIG	Ammonia Injection Grid
AQCS	Air Quality Control Systems
BACT	Best Available Control Technology
BOP	Balance-of-Plant
BFB	Bubbling Fluidized Bed
BMP	Best Management Practices
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
BRM	BioResources Management, Inc.
Btu/lb	British Thermal Units Per Pound
CAIR	Clean Air Interstate Rule
CEMS	Continuous Emission Monitoring System
City	City of Alachua
CO	Carbon Monoxide
COC	Conditions of Certification
COD	Commercial Operation Date
dBA	Decibel
DC	Direct Current
DCS	Distributed Control System
DEP	Department of Environmental Protection
DGS	Deerhaven Generating Station

Abbreviation	Term/Phrase/Name
DSI	Dry Sorbent Injection
EAF	Equivalent Availability Factor
EDI	Electro-deionization
EFOR	Equivalent Forced Outage Rate
EMI	Energy Management, Inc.
EPA	Environmental Protection Agency
ERI	Electrical Resistivity Imaging
FDEP	Florida Department of Environmental Protection
FGR	Flue Gas Recirculation
FP&L	Florida Power & Light
FRCC	Florida Reliability Coordinating Council, Inc
FSC	Forest Stewardship Council
GADS	Generating Availability Data System
gr/dscf	Grains Per Dry Standard Cubic Feet
GREC	Gainesville Renewable Energy Center
GRU	Gainesville Regional Utilities
GSU	Generator Step-up
HAP	Hazardous Air Pollutants
HCL	Hydrogen Chloride
HF	Hydrogen Fluoride
HHV	Higher Heating Value
HP	High Pressure

Abbreviation	**Term/Phrase/Name**
Hz	Hertz
IB	Industrial Boiler
ICE	Internal Combustion Engine
kgal	Thousand Gallons
kW	Kilowatts
lb/hr	Pounds Per Hour
lb/MMBtu	Pounds Per Million British Thermal Units
LP	Low Pressure
MACT	Maximum Achievable Control Technology
McHale	McHale & Associates Inc.
MGD	Million Gallons Per Day
MOU	Memorandum of Understanding
MSS	Minimum Sustainability Standards
MVA	Megavolt Ampere
MW	Megawatts
N_2	Nitrogen
NAES	North American Energy Services Corporation
NAAQS	National Ambient Air Quality Standards
NERC	National Electric Reliability Council
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NFPA	National Fire Protection Agency
NH_3	Ammonia

Abbreviation	**Term/Phrase/Name**
NIST	National Institute of Science and Technology
NO_2	Nitrogen Dioxide
NSPS	New Source Performance Standard
O_2	Oxygen
O&M	Operations and Maintenance
PM	Particulate Matter
PPA	Power Purchase Agreement
ppmvd	Parts Per Million By Volume Dry
PSD	Prevention of Significant Deterioration
PSIG	Pounds Per Square Inch Gauge
RATA	Relative Accuracy Test Audit
RCRA	Resource Conservation Recovery Act
REC	Recognized Environmental Condition
RFID	Radio Frequency Identification
RO	Reverse Osmosis
RPM	Revolutions Per Minute
SAM	Sulfuric Acid Mist
SCA	Site Certificate Application
SCR	Selective Catalytic Reduction
SCBA	Self-contained Breathing Apparatus
SNCR	Selective Non-Catalytic Reduction

Abbreviation	**Term/Phrase/Name**
SO_2	Sulfur dioxide
SO_3	Sulfur trioxide
SS	Station Service
STG	Steam Turbine Generator
Tons/MWh	Tons Per Generation
tph	Tons Per Hour
tpy	Tons Per Year
UPS	Uninterruptible Power Supplies
WWTP	Wastewater Treatment Plant
V	Volt
VOC	Volatile Organic Compound
ZLD	Zero-liquid Discharge

STATEMENT OF LIMITATIONS

This report may have been prepared under, and only be available to parties that have executed, a Confidentiality Agreement with Gainesville Regional Utilities. Any party to whom the contents are revealed or may come into possession of this document is required to request of Gainesville Regional Utilities if such Confidentiality Agreement exists. Any entity in possession of, or that reads or otherwise utilizes information herein, is assumed to have executed or otherwise be responsible and obligated to comply with the contents of such Confidentiality Agreement. Any entity in possession of this document shall hold and protect its contents, information, forecasts, and opinions contained herein in confidence and not share with others without prior written authorization from Gainesville Regional Utilities.

In preparation of this report, Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") has relied upon information provided by Gainesville Regional Utilities and the owners and operators of the Gainesville Renewable Energy Center. While there is no reason to believe that the information provided is inaccurate or incomplete in any material respect, Burns & McDonnell has not independently verified such information and cannot guarantee or warranty its accuracy or completeness.

Burns & McDonnell's estimates, analyses, and recommendations contained in this report are based on professional experience, qualifications, and judgment. Burns & McDonnell has no control over weather; cost and availability of labor, material, and equipment; labor productivity; energy or commodity pricing; demand or usage; population demographics; market conditions; changes in technology; and other economic or political factors affecting such estimates, analyses, and recommendations. Therefore, Burns & McDonnell makes no guarantee or warranty (actual, expressed, or implied) that actual results will not vary, perhaps significantly, from the estimates, analyses, and recommendations contained herein.

Burns & McDonnell has not been engaged to render legal services. The services Burns & McDonnell provides occasionally require the review of legal documents, statutes, cases, regulatory guides, and related matters. The opinions, analysis, and representations made in this report should not be construed to be legal advice or legal opinion concerning any document produced or reviewed. These documents and the decisions made in reliance of these documents may have serious legal consequences. Legal advice, opinion, and counsel must be sought from a competent and knowledgeable attorney.

This report is for the sole use, possession, and benefit of Gainesville Regional Utilities for the limited purpose as provided in the agreement between Gainesville Regional Utilities and Burns & McDonnell. Any use or reliance on the contents, information, conclusions, or opinions expressed herein by any other party or for any other use is strictly prohibited and is at that party's sole risk. Burns & McDonnell assumes no responsibility or liability for any unauthorized use.

1.0 EXECUTIVE SUMMARY

The following section provides a summary of the key conclusions and observations reached within this independent review.

1.1 Introduction

Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") was retained by Gainesville Regional Utilities ("GRU") to conduct an Independent Engineer's Due Diligence Evaluation (Study) of the Gainesville Renewable Energy Center ("GREC," "Plant," "Facility," "Site," "Project"). The Plant is a biomass-fired power production facility with a net nameplate capacity of 102.5 megawatts ("MW") located in Gainesville, Florida. The Facility reached commercial operation in December 2013.

GRU currently has a power purchase agreement ("PPA") with GREC. GRU is considering acquiring ownership of the Plant. The purpose of the Study was to evaluate whether the Plant was designed, constructed, operated, and maintained in a manner that will be able to provide long-term, dependable service as a biomass-fueled generation resource.

Burns & McDonnell staff attended a management presentation, plant staff interview, and site visit in Gainesville from July 26, 2017 through July 28, 2017. Additionally, Burns & McDonnell requested and reviewed numerous engineering, permits, and contractual documents provided by GREC regarding the design and operation of the Facility.

1.2 Conclusions

Based on the information reviewed and the results of the Independent Engineer's Report, Burns & McDonnell concludes that the Plant appears to be designed and constructed in accordance with generally accepted industry standards. The Facility utilizes proven and reliable technologies and a similar configuration to other biomass-fueled power resources. The Plant's capital costs, fixed and variable operations and maintenance ("O&M") costs are within reasonable range for a unit of this size and technology. The Plant appears to have the appropriate contracts in place to support the Facility's operations. Burns & McDonnell believes that if the Plant is operated and maintained in accordance with good industry standards, the Plant should be fully capable of providing long-term, reliable service as an intermediate generation resource.

2.0 SITE VISIT

Representatives from Burns & McDonnell visited the Plant from July 26, 2017 through July 28, 2017. The purpose of the site visit was to gather information to conduct the independent engineer's due diligence evaluation, interview the plant management and operations staff, and to conduct an on-site review of the Plant site. The following GREC staff provided information during the site visit, including Energy Management, Inc. ("EMI") personnel, O&M contractors from North American Energy Services Corporation ("NAES"), and fuel supply contractors from BioResources Management, Inc. ("BRM").

- Mr. Len Fagan, Vice President Engineering and Asset Manager (EMI)
- Mr. Al Morales, Managing Director, Asset Manager, and Chief Financial Officer (EMI)
- Carolyn Wasdin, Operations Administrator (EMI)
- Steve Marsh, Plant Manager (NAES)
- Ali Leaphart, Plant Engineer and Environmental Specialist (NAES)
- Mike Buonsignore, Operations Supervisor (NAES)
- Richard Schroeder, President (BRM)
- Brian Condon, Fuel Supply Manager for GREC (BRM)

The following Burns & McDonnell representatives comprised the independent engineer's evaluation team:

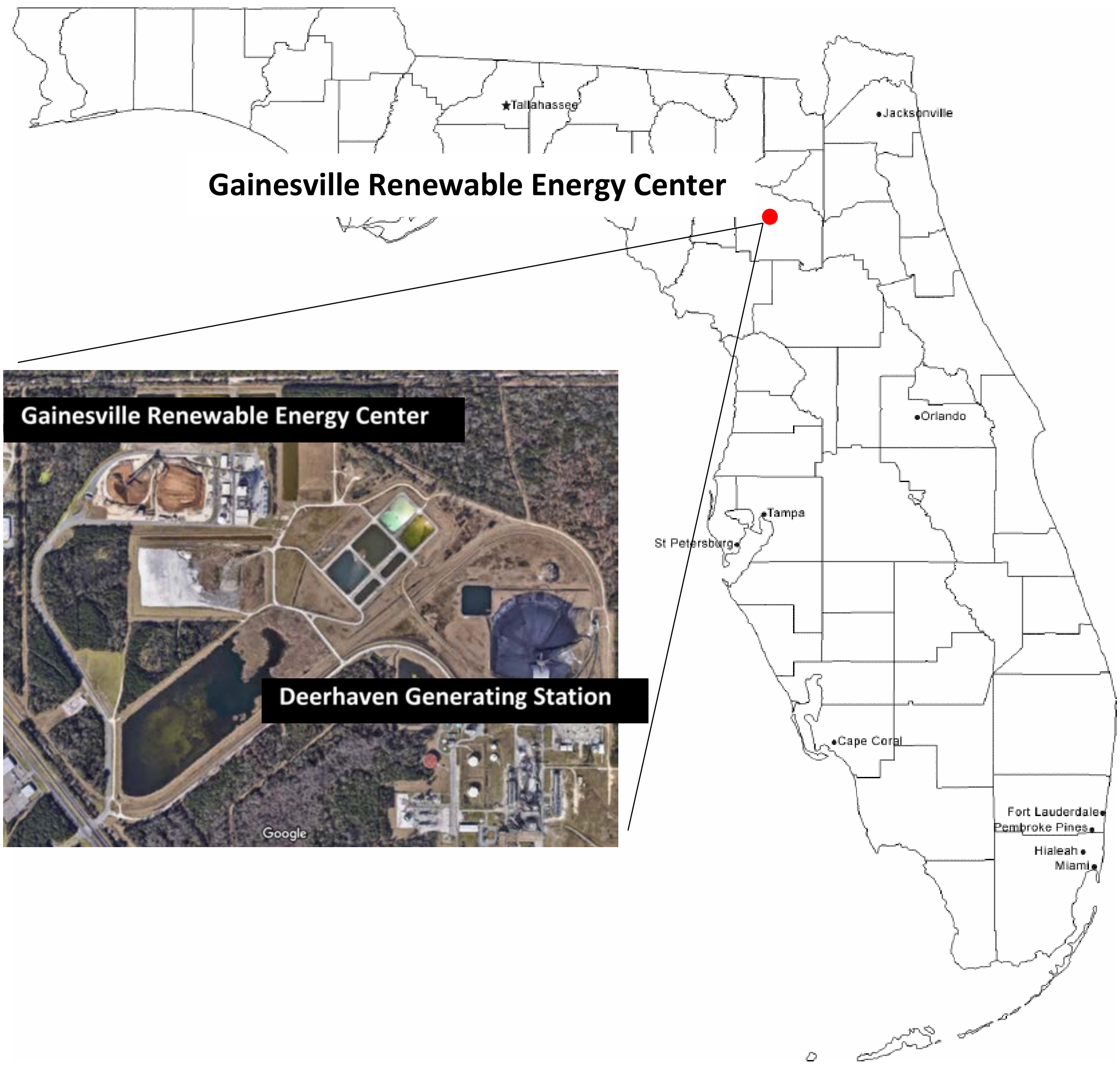
- Mr. Mike Borgstadt, Associate Project Manager and Mechanical Engineer
- Mr. Sandro Tombesi, Associate Mechanical Engineer
- Mr. Cory Hansen, Senior Mechanical Engineer and Material Handling Specialist
- Mr. Chris Howell, Associate Environmental Specialist
- Mr. Block Andrews, Director of Environmental Solutions (via conference call)

During the site visit, the Plant was not producing electrical generation and was in a status of long-term standby at the direction of GRU. The Facility was accepting wood fuel deliveries at the time of the site visit.

3.0 PLANT DESCRIPTION

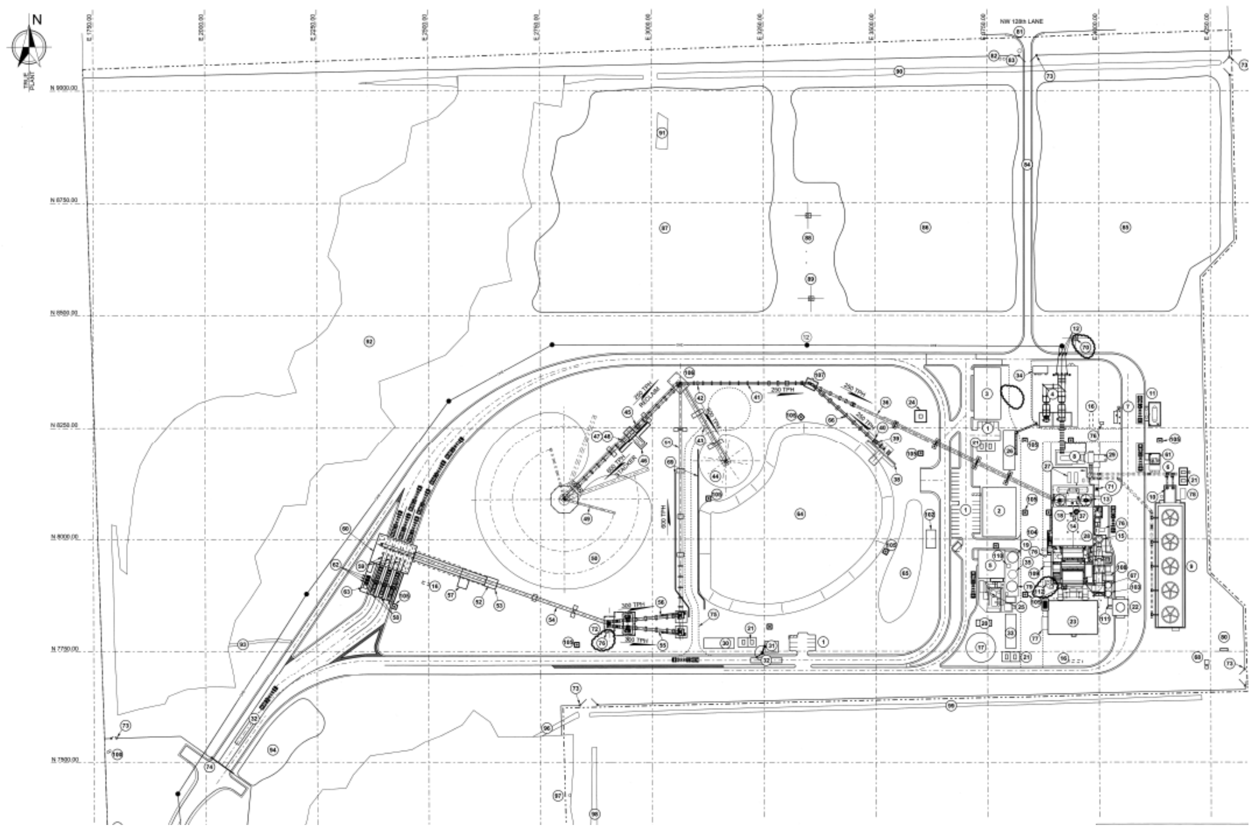
The Plant sits on a 131-acre site located in Alachua County, Florida, approximately 10 miles northwest of Gainesville, Florida. The Site is also adjacent to GRU's Deerhaven Generating Station ("DGS"). Figure 3-1 provides an overall vicinity map for the Gainesville Renewable Energy Center.

Figure 3-1: Vicinity Map



The Plant includes one 100 percent woody biomass bubbling fluidized bed ("BFB") boiler with selective catalytic reduction ("SCR"), baghouse, sorbent injection, zero-liquid discharge ("ZLD"), and a steam turbine generator ("STG"). Figure 3-2 presents the site layout for the Plant.

Figure 3-2: Site Layout



3.1 General Introduction

The Project is a nominal rated 102.5 MW net (116 MW gross) biomass-fired electric generating facility, and consists of a biomass fuel handling system, a biomass-fired boiler and associated ash handling systems and air quality control systems ("AQCS"), an axial exhaust condensing STG with evaporative cooling tower, and auxiliary support equipment. Commercial operation was initiated in December 2013.

The Facility incorporates a ZLD system to eliminate industrial wastewater discharges pursuant to its permits. The Project appears to have been designed in accordance with power industry standards, therefore with standard O&M practices its technical service life should achieve at least 30 to 40 years of service.

The Project utilizes a Metso (now Valmet) HYBEX BFB boiler with sodium bicarbonate injection to produce superheated steam. A baghouse is included to control particulate matter ("PM"). The 19 percent aqueous ammonia injection SCR system that follows the baghouse provides additional NOx control. Superheated steam from the boiler is sent to a single Siemens STG with four feedwater heating extractions. The steam turbine generates electricity before exhausting axially into a two-pass condenser, with its cooling water provided by a five-cell wet evaporative cooling tower.

Electric power is produced by the STG at a nominal voltage of 13.8 kilovolts ("kV"). A two-winding generator step-up ("GSU") transformer at the on-site substation increases the voltage to 138 kV which then connects through aerial transmission lines to the interconnection point with GRU's looped 138 kV transmission system. Station service ("SS") power is fed back through a dedicated SS transformer also located within the on-site substation.

The Project, as presented in Figure 3-1, is located within the confines of GRU's existing Deerhaven Power Plant site on property leased from the City of Gainesville (d/b/a GRU). GREC indicated GRU has title to 100 percent of the Plant's output, including all environmental attributes (such as renewable energy credits, carbon offsets, etc.).

GREC purchases biomass feedstock for fuel generally from within a 50 to 55-mile radius of the site (urban wood waste, as described below, has a larger economical radius, approximately 75 miles or more in some cases). The primary fuels for the Project are wood and wood waste from the following categories:

- In-woods – represents over 80 percent of fuel supply to the Plant over the past 4 years and consists of wood from agricultural and forestry land management activities including site preparation, fire fuels reduction, salvage, and land clearing.
- Mill residue – represents approximately 5 to 10 percent of the fuel supply over the past 4 years and consists of waste from primary and secondary wood mills.
- Urban – approximately 10 percent of the fuel supply to the Plant over the past 4 years and consists of curbside yard/storm debris, tree service and land-clearing debris.

Wood is delivered in chipped and sawdust form with a maximum size of 6 inches ("in") nominal, with small amounts of sawdust and fines. The Facility is not designed to burn treated wood nor any other solid or liquid fuels. Natural gas provides start-up fuel to the unit. Natural gas cannot be used as a primary/low-load fuel due to the location of the gas burners at the boiler.

The BFB boiler produces up to approximately 930,000 pounds per hour ("lb/h") superheated steam and sends it to the Siemens STG. The STG is a single flow, single casing turbine with high pressure ("HP") and low pressure ("LP") sections and four extractions, and exhausts axially to the condenser. Condensate is pumped to a gland condenser and on to the LP feedwater heater. The water from the LP feedwater heater goes to the deaerator, where it mixes with the condensate from the steam coil boiler air heater and LP steam. From the deaerator, the hot water is pumped by 2 x 100 percent ring section boiler feed pumps supplied by Flowserve to two HP heaters and then is returned to the boiler.

Plant makeup water can be supplied from two full capacity on-site process wells, as well as reclaimed water from the City of Alachua. The wells can provide the entire water needs for the Project; however, reclaimed water is used as available, which is usually the case according to plant staff. Wastewater is processed in the ZLD system. Wastewater from the Project is recycled or reused to comply with all applicable permits.

Solid waste generated by plant operation include bottom ash, fly ash, and ZLD solids. The bottom ash and ZLD solids are shipped off-site to be landfilled. The fly ash is also shipped off-site for beneficial re-use.

3.1.1 Site Conditions

The Project site is located east of U.S. Highway 441, south of Northwest 128th Lane, and west of the Deerhaven Generating Station in Gainesville, Florida, as presented in Figure 3-1. GREC has leased approximately 131 acres from GRU for the Project site. GREC indicated it has also obtained easements to allow for the operation, and maintenance of the Project.

The main parcel of land consists of approximately 131 acres. The biomass Plant utilizes approximately 60 acres of the parcel. Electric power produced in the STG at the nominal generator voltage is increased in voltage at an on-site substation and transmitted through aerial transmission lines to the interconnection point with GRU's looped 138 kV transmission system. GRU's transmission system is interconnected with Duke Energy and Florida Power & Light ("FP&L").

The site, easements, and additional areas appear to be suitable for operation and maintenance of the Plant.

3.1.2 Civil & Structural Design

GREC indicated that geotechnical subsurface investigations and studies were conducted prior to commencement of construction. The soils at the site are a mixture of sands and potentially expansive soils. Geotechnical soil test borings performed prior to construction found loose to medium dense sand with silt to silty sand to a depth of approximately 10 feet followed by loose to medium dense clay sand to stiff sandy clay to a depth of approximately 40 feet. This type of soil is common in Florida, and typical foundation construction methods were used during construction including:

- For shallow foundations, structures were supported on conventional shallow foundations, post-tensioned slabs, or thickened edge monolithic slabs.
- For deep foundations, structures were supported on augured cast in-place (augurcast) piles or drilled shafts for support of the heavily loaded structures.
- For large underground structures such as the truck tipper facility, structural slab systems in conjunction with anchor drilled piers were used to resist buoyancy hydrostatic pressure due to high groundwater.
- Pavements for roads and parking were designed as a function of the anticipated traffic loadings.

According to GREC, additional soils testing was performed prior to construction including electrical resistivity imaging ("ERI") investigation of the site to evaluate potential site specific geological conditions (including potential for sinkholes). The focus of the investigation was on a 39-acre area of the site that includes the power block equipment. According to GREC, the geotechnical engineer concluded that the ERI test data are indicative of a stable geologic subsurface suitable for development, and none of the data patterns were indicative of sinkhole activity or other unstable conditions.

A limited area of horizontally disparate resistivity was detected in the northeast portion of the site. However, no major plant equipment was placed in this area.

Road designs appear to conform to Florida Department of Transportation requirements, with roads surfaced with asphalt. According to information received from GREC, the road access from the highway was widened and improved during construction. The existing turning lanes were lengthened to support increased truck traffic (up to 150 to 160 trucks per day as reported by plant personnel when the Plant is operating at full capacity). Roads, drives, and surfaced areas are well maintained and suitable for Project operation.

According to GREC, the structural design of the power plant was done in accordance with State of Florida Building Code and the International Building Code, 2006 edition. The structural design is suitable and consistent with good engineering practice. GREC indicated that based on geotechnical investigations, deep foundations using drilled piers or augured cast-in-place piles were utilized to support heavy structures, while spread or strip type footings were utilized for light structures.

Steel structures are used throughout the Plant as needed. Structural steel is painted indoors and galvanized outdoors, which is suitable per industry standards.

Hoists are located throughout the Plant to facilitate maintenance. Eight manually operated monorail chain hoists are located within the Plant for maintenance and access to equipment such as boiler feed pumps, circulating water pumps, condensate pumps, auxiliary cooling pumps, and wood yard hogs. Fourteen (14) electric hoists are also provided for boiler equipment maintenance. No permanent crane is provided for the enclosed outdoor steam turbine, but rather adequate space is provided to allow servicing by means of mobile cranes. The number and location of hoists are well suited to the Plant maintenance needs.

3.2 Power Block

The Plant consists of one Valmet (formerly known as Metso) BFB boiler, Wolf biomass storage and handling equipment, one Siemens condensing STG, and auxiliary equipment including a cooling tower, well pumps, water treatment equipment, and air compressors. The Plant has a nominal net capacity of 102.5 MW.

3.2.1 BFB Boiler Technology Description

Metso (now incorporated into Valmet) engineered, procured, manufactured, and delivered the BFB boiler for the Project. BFB combustion for power generation has been around since the mid-1980s. Metso developed HYBEX in the 1990s, a proprietary technology for BFB boilers suitable for a wide range of fuel moistures, as suits biomass facilities, with biomass fuels often having high moisture content. The HYBEX system also includes the patented "Hydro Beam" floor grate for easy removal of coarse material from the furnace.

Metso has installed or converted more than 200 HYBEX boilers worldwide, and was well qualified to design and construct the BFB boiler. BFB boilers are well suited to handle fuels with low heat value and high moisture content. The boiler overall constructive simplicity, together with the turbulent, low temperature bed and the ability to regulate the fluidization velocity and secondary and tertiary air quantities, gives the BFB fuel flexibility, good combustion efficiency (about 90 percent), and low emissions.

A BFB boiler consists of natural sand in a fluidized air suspension at the bottom of the boiler. Larger fuel particles and residual char burn within the bed, while smaller particles burn above it. The combustion is sustained and controlled with fluidizing (primary) and over-fire (secondary and tertiary) air. The fluidizing bed benefits from a large combustion zone and high turbulence, allowing efficient solid-to-gas contact and high heat transfer rates. The over-fire air completes the combustion and regulates oxygen content in the flue gas, thereby regulating emissions. The Metso design also includes a tall furnace for prolonged mixing and combustion duration. A fuel gas recirculation fan sends cooler flue gas back into the furnace to help with temperature control along.

The boiler is designed to burn forest residue, mill residue, pre-commercial tree thinnings, used pallets, and clean urban wood waste including woody tree trimmings that are generated by landscaping contractors, power line clearance contractors, and other non-forestry related sources of woody debris. The BFB technology can handle a wide variation in wood supply, and is generally considered very fuel flexible. The boiler also uses natural gas as an auxiliary fuel for startup, utilizing four burners to get the sand bed to a minimum temperature of 900°F. The boiler system by design produces approximately 930,000 lb/h of superheated steam at 1,620 pounds per square inch gauge ("psig") and 1,005°F, with feedwater provided to the boiler economizer at 440°F.

The plant design fuel range includes moisture contents from 40 percent to 50 percent. The BFB technology can accommodate moisture contents above and below this range as well. Changes in moisture content should not impact output, but will impact heat rate.

The boiler system receives fuel via two metering bins, with a total storage capacity of approximately 45 minutes. Each bin delivers the fuel to three metering screws via drag conveyors. From the metering screws, the fuel is delivered to fuel chutes connected to the furnace.

Typical fluidization velocities are low, which minimizes sand loss in normal operation. Most of the sand losses are through the coarse material removal system, while a minor amount breaks into finer particles and is carried by the flue gas. Reclaimed and makeup sand for the boiler is housed in a sand silo and is fed to the boiler by gravity through a rotary valve feeder connected to a chute.

Primary air (fluidizing air) is introduced into the furnace by the primary air fan. This air is heated with a flue gas air heater before being introduced into the furnace through evenly spaced fluidizing air nozzles penetrating the floor. Over-fire air, to complete the combustion process, is introduced into the furnace by the secondary air fan. This air is heated by auxiliary steam and four stages of flue gas. Over-fire air is separated into two flows: a secondary and a tertiary stage. The secondary and tertiary airflows are delivered to the furnace through constant velocity nozzles located at the front and rear walls.

The post-combustion gases (flue gas) leave the furnace after reaching the radiant superheater section on top of the boiler, which enables steam production. From there the flue gas flows through a second and third superheater surface to sustain this process. After its passes through the superheaters, the flue gas flows through the finned tube economizer bundles to heat the water in preparation for steam generation. The residual heat in the flue gas is then used to condition the combustion air via primary and secondary tubular air heaters, which increase the efficiency of the boiler. In addition, after passing the boiler economizer, dry sorbent injection is used to control flue gas hydrogen chloride ("HCl"), hydrogen fluoride ("HF"), and sulfur oxides (including sulfur dioxide ("SO_2") and sulfur trioxide ("SO_3"). The cooled gas finally reaches the baghouse filter for removal of airborne particles, and from there it is routed back through an additional stage of air heaters and then the flue gas is treated by a SCR system using 19 percent aqueous ammonia injection to reduce NOx emissions. To maintain appropriate flue gas temperature into the SCR, steam coil air preheaters are used to increase boiler inlet air temperatures for part load and cold ambient conditions.

After passing through the SCR, the flue gas is ducted to the stack via a single induced draft fan located downstream, which maintains flue gas pressure in the furnace at approximately -0.02 pounds per square inch absolute ("psia").

The boiler includes a HYBEX floor grate design, which has a cooling effect on the ash and allows for more than 30 percent of the floor to remain open for ash removal. The coarse material (bottom ash) falls from the bed into a system of ash hoppers, conveyors, and chutes that ends in an ash container. Fly ash is collected at three points in the flue gas system: the second pass hopper, the third pass hopper, and the baghouse. Ash collected during the second and third pass is carried to the handling system via a screw conveyor. The baghouse includes a pulse jet type online cleaning system that collects fly ash in the baghouse hoppers.

Boiler emissions are controlled by regulating available oxygen during combustion and using a post-combustion SCR system with catalyst bed and ammonia injection. The boiler design also includes dry sorbent flue gas cleaning to remove acid gases. Sodium bicarbonate sorbent is injected after the economizer into the baghouse to control HF, HCl, and SO_2/SO_3. Table 3-1 lists equipment included with the boiler that was furnished by Metso.

Table 3-1: Major Boiling System Equipment

Equipment
Bubbling Fluidized Bed Boiler
Drum, furnace, superheaters, steam attemperators, economizer bundle with headers, structural supports, and boiler casing.
Combustion Air System
(a) Primary (fluidizing) air system including one air fan, silencer, inlet vane flow control, and ducting with air heater, fuel feed and ammonia system. (b) Secondary (Burner/Over fire) air system including one variable frequency controlled air fan, silencer, and ducting with air heater, constant velocity nozzles, and cooling air piping for main flame scanner.
Flue Gas System
Primary air tubular air heater, secondary air tubular air heater, flue gas ductwork, pulse jet baghouse, induced draft fan, and insulated carbon steel flue gas stack.
Flue Gas Recirculation (FGR) System
One Flue gas recirculation fan with inlet vane flow control and ducting.
Fuel Feed System
Two metering bins totaling approximately 45 minutes of storage capacity, including rotating screw reclaimers, two drag chain conveyors, six metering screws, six rotary airlocks, fuel chutes, and structure.
Sand Feed System
One sand storage silo with pneumatic fill line, vent piping, and structure. Screw conveyor discharge with feed chutework.
Coarse Material Handling System
Twelve removal hoppers with manual and pneumatic isolation gate valves, three water cooled screw conveyors, one drag conveyor with multiple inlets, and a material sieving and recirculation system.
Fly Ash Handling System
Two second pass ash hoppers, one third pass hopper with two motor driven screw conveyors, one ash transfer screw, and multiple bag filter hopper outlet connections. Vacuum conveying system consisting of common conveying line, filter separator, two vacuum blowers, two silo fluidizing blowers, bin vent filter, pugmill and dry unloading spout.
Burners
Four natural gas fired startup burner assemblies.
SCR System
Vanadium pentoxide based catalyst bed, one forwarding skid, including two piston type metering pumps, ammonia valve racks, and ammonia injection manifolds. Two bed locations are included for redundancy.
Deaerator
One 20-minute deaerator with storage tank and supporting steel.
Other
Distributed Control System (DCS), transmitters, and elevator.

3.2.2 Steam Cycle Description

The steam cycle includes a single flow turbine operating at 1,590 psig, with 1,000°F steam temperatures. The turbine exhausts steam to a water-cooled condenser at a design back pressure of 2.5 inches of mercury absolute ("in. HgA"). Waste heat is rejected from the steam cycle through a plant common closed loop circulating water system to a five-cell mechanical draft cooling tower.

Condensate from the condenser hot well is forwarded to the boiler through a gland condenser and a four-heater feedwater heating system. The condenser is equipped with two 100 percent capacity condensate hot well pumps that pump through the gland steam condenser. Water is forwarded from the gland condenser to the feedwater heating system. The feedwater heating system consists of one closed LP heater, one open deaerating heater, and two closed HP heaters. The steam cycle equipment is designed for constant pressure operation. Two 100 percent motor driven ring section Flowserve boiler feed pumps deliver feedwater to the HP section of the steam cycle. The overall arrangement and common equipment features are good practice for a utility quality power plant.

The feedwater system consists of four feedwater heaters: one LP heater, one deaerator, and two HP heaters. All heaters receive steam supplied from steam turbine extraction points.

Two 100 percent Flowserve condensate pumps are provided. Condensate pump discharge flows through the gland steam condenser, the LP feedwater heater, and into the open deaerator. The condensate flow leaving the deaerator is forwarded by one of two 100 percent capacity Flowserve boiler feed pumps. One boiler feed pump provides full load capability for the Plant, with the second boiler feed pump on standby. The discharge of the boiler feed pumps flows through the two HP feedwater heaters to the boiler.

The feedwater and condensate systems include adequate redundancies that will allow continued operation in the event of a component failure.

The heat rejection system for the Plant is comprised of a Holtec single two-pass surface condenser, circulating water system, cooling tower, and closed-loop auxiliary cooling system. Two 75 percent capacity circulating water pumps circulate water through the condenser. The circulating water pumps are low temperature, low pressure, high flow vertical pumps that are typically highly reliable. The single pump capacity of 75 percent was selected to ensure that one pump is sufficient to sustain operation at the minimum 70 MW output required by the PPA.

The circulating water pumps take suction from the cooling tower basin and discharge to a common header routed to the condenser. After the circulating water has cooled and condensed steam within the surface condenser, it is returned to a common header that is directed back to the cooling tower.

The two-pass divided water box condenser is designed to maintain turbine back pressure at or below 2.5 in. HgA, with STG valves wide open. The circulating water flow rate through the condenser is based on the valves wide open condenser duty and a wet-bulb temperature of 78°F. Condenser tubes and tube sheets are 317SS stainless steel, which should afford them good reliability.

The Evaptech mechanical draft, counterblow cooling tower rejects the heat from the condensers and auxiliary cooling water system. The design wet-bulb temperature is 78°F. One of the five cooling tower cells can be removed from service for maintenance and testing without affecting plant output.

3.2.3 Steam Turbine and Generator

The STG was designed, manufactured, and delivered by Siemens. Siemens has more than 20,000 installed steam turbine units through more than 100 years of experience and continuous development. According to information received from GREC, for SST-700 and STT-900 turbines of the industrial size class, Siemens counts over 280 installations since 1974. The unit installed at GREC is an SST-900, which includes over 60 installations worldwide.

The steam turbine is a model SST-900 single casing steam turbine designed for 115,900 kilowatts ("kW") of gross capacity, operating at 3,600 revolutions per minute ("rpm") with direct drive to the generator. The SST-900 units are built from a series of standardized sections and modules, which allows the blade lengths and number of stages to be customized to specific project requirements. The unit includes a symmetrical casing, a simple single valve inlet instead of a valve chest, axial condensing exhaust, and four bleed ports for feed water heating. Its relatively small dimensions on the hot path components and consequent smaller thermal inertia allow this condensing turbine to accept shorter start-up times and quicker load changes. The STG is installed outdoors in a full enclosure.

The STG design conditions include 910,100 lb/h flow at 1,590 psia and 1,000°F at the inlet, with 628,005 lb/h at 1.227 psia condensate exhaust flow after feedwater heating extractions.

STG major maintenance is on a 60,000-operating-hour cycle, which would be every 8 years at base load operation. Since the Plant has operated for a total of about 4,000 hours since the commercial operation date ("COD"), STG major maintenance will not be required for several more years. Its need should be re-evaluated as more operating experience is gained.

Siemens provided a BRUSH DAX two-pole air-cooled cylindrical rotor generator. The BRUSH DAX units have been extensively used with industrial and aeroderivative gas turbines, as well as with steam turbine applications. The generator is 60 hertz ("Hz") three-phase and designed to operate at a 0.85 (lagging) power factor at 13.8 kV, with output of 116.45 MW (or 136.59 megavolt ampere ("MVA")).

The cooling circuit forces air around the generator through two axial flow fans on the rotor shaft. The air is cooled by a water-cooled heat exchanger.

3.2.4 Emissions Control

The Plant controls NOx emissions in the boiler using both Low NOx burners and over-fire air.

Exhaust from the boiler passes through a baghouse for removal of fly ash. Downstream of the baghouse, exhaust gas enters the SCR and NOx emissions are further reduced. The SCR in this case is a low-dust design, located downstream of a baghouse, to potentially mitigate the concern of catalyst deactivation from alkalines in the biomass ash. Nineteen (19) percent aqueous ammonia is used as the reagents for NOx reduction. Ammonia is injected into the ammonia injection grid ("AIG") upstream of the statis mixers and flow straightening devices. Catalyst replacement can be scheduled to coincide with major scheduled outage of the Plant so there will be no impact on the overall availability.

A dry sorbent injection ("DSI") system is used in the unit to remove SO_2. The sodium bicarbonate injection is used to reduce acidic gas emissions, such as for HF and HCl as well.

3.3 Material Handling

3.3.1 Fuel Conveying

The biomass fuel handling system consists of unloading, screening/hogging, stackout/storage, reclaim and feed sub-systems.

The unloading system consists of three hydraulic truck tippers, dust collection, and unloading belt conveyor. Fuel delivery trucks are received at a 135-ton capacity truck scale to register the entering weight and other information via radio frequency identification ("RFID") tag. After weighing, the trucks proceed around the wood yard to the truck unloading enclosure (near the main entrance to the Plant). The unloading structure consists of three 60-ton drive-through dumpers allowing simultaneous delivery of up to three truckloads. After unloading, the trucks are weighed again to register the amount of wood delivered. Each unloading hopper is equipped with dual spike rolls as well as in-situ moisture measurement. The unloader hoppers each discharge to a common 72" unloading belt conveyor. The conveyor includes a magnetic separator and a metal detector for removing tramp material. The hoppers as well as the conveyor load points are equipped with dust collection provided by a baghouse style dust collector located outdoors near the conveyor exit tunnel. A rotary feeder and screen conveyor return the collected wood dust to the unloading belt conveyor, downstream.

From the fuel receiving hoppers, the unloading conveyor delivers fuel to the screening/hogging building at 600 short tons per hour ("tph"). The screening/hogging system reduces oversized fuel to 2.5" or smaller sizes. There are two disc screen/hog trains, each with 300 tph capacity. The hogs have a design capacity of 100 tph each; this is sufficient due to the amount of undersized material separated by the screens. Both trains include a 54" belt conveyor to feed a common stackout transfer conveyor rated at 600 tph. The common 72" belt conveyor feeds Transfer Tower #1, to divert fuel to either of the two stackout systems.

The stackout system includes an automatic circular stacker/reclaimer system and a manual telescoping chute stackout system. The circular stacker/reclaimer has approximately 270º degrees of rotation. It forms a kidney-shaped pile and consists of a luffing and slewing boom belt for stackout and a luffing and slewing chain reclaim system. The telescoping chute boom is fixed (no luffing/slewing capability). Dust suppression spray water is applied prior to loadout through the chute to reduce fugitive dusting.

The two fuel storage piles have a collective storage capacity of 243,300 cubic yards (approximately 59,122 tons or 20 days at full load) and are separate from each other, isolated by transfer conveyors. The fuel piles are not typically segregated by wood supply, but are segregated to maintain first-in, first-out fuel inventory practices. Wood/sawdust from various sources is passively blended in the unloading/stackout systems. Two in-ground chain reclaimers are used to provide mobile-equipment assisted reclaim (via two Wagner rubber-tired chip dozers) from either of the two stackout piles. All reclaim systems feed a series of 48" reclaim belt conveyors to transfer to the unit feed belt, Conveyor 9, at Transfer Tower #2. The reclaim and feed conveyors are designed for 250 tph capacity but are typically run at 200 tph per discussion with plant personnel.

The 48" feed conveyor from Transfer Tower #2 is equipped with a belt-rip detection system two drives (one redundant) for added reliability. The conveyor is equipped with dust collection at the head of the conveyor (combined with the collection from the metering bin which it feeds). The discharge chutework includes a motor-operated splitter gate to feed the first metering bin, and/or another 48" transfer belt conveyor to feed the other bin. Wolf's scope of supply ended at the chutework interface to the metering bins. The metering bin/boiler feed system was furnished by Raumaster Oy, a supplier under Metso contract.

Each metering bin includes a screw reclaim system, drag chain conveyor with balancing pocket, feed/robbing screw conveyors and three rotary valve/feed chutes. The system is illustrated on Figure 3-3, and is followed by a more detailed description of this process in Table 3-2.

Figure 3-3: Material Handling System Flow

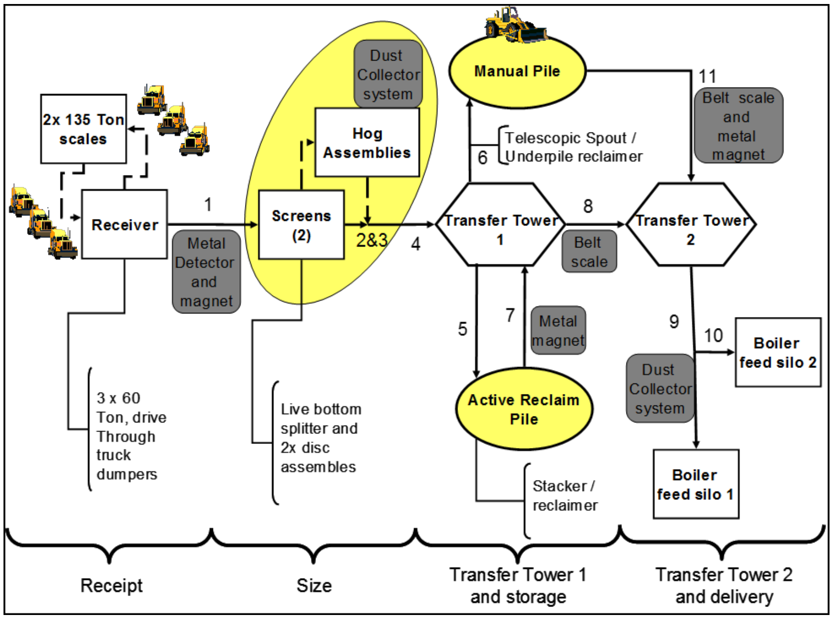


Table 3-2: Conveyors of the Material Handling System

Conveyor	Size Width	Size Capacity	Material Size	General Description
No. 1	72 inches	600 tph	6 inches	From the In-Pit Receiving Hoppers to splitting bins
No. 2	54 inches	300 tph	2.5 inches	Provides approximately 12'-0 inch of vertical lift. From one (1) of the Screen/Hogs to Conveyor No. 4
No. 3	54 inches	300 tph	2.5 inches	Provides approximately 12'-0 inch of vertical lift. From one (1) of the Screen/Hogs to Conveyor No. 4
No. 4	72 inches	600 tph	2.5 inches	Provides approximately 80'-0 inch of vertical lift. From Conveyors No. 2 and 3 to either Conveyor No. 5 or 6
No. 5	72 inches	600 tph	2.5 inches	Provides approximately 46'-9 inch of vertical lift. From Conveyor No. 4 to Stacker/Reclaimer No. 1
No. 6	72 inches	600 tph	2.5 inches	Provides approximately 29' of vertical lift. From Conveyor No. 4 to stockpile
No. 7	48 inches	250 tph	2.5 inches	Provides approximately 13'-0 inch of vertical lift. From the Stacker/Reclaimer to Conveyor No. 8 or from Underpile Reclaimer No. 1 to Conveyor No. 8
No. 8	48 inches	250 tph	2.5 inches	Provides approximately 13' of vertical lift. From Conveyor No. 7 to Conveyor No. 9
No. 9	48 inches	250 tph	2.5 inches	Provides approximately 121'-9 inch of vertical lift. From Conveyor No. 8 or Conveyor No. 11 to Conveyor No. 10 or Boiler Feed Silo 1
No. 10	48 inches	250 tph	2.5 inches	From conveyor No. 9 to Boiler Feed Silo 2.
No. 11	48 inches	250 tph	2.5 inches	Provides approximately 13' of vertical lift. From Underpile Reclaimer No. 2 to Conveyor No. 9

In comparison to the fuel handling system design conveying capacities, the boiler will require a full load fuel input of approximately 134 tph (assuming 90 percent availability). The material handling system's design includes adequate unloading and feed rate multipliers (600 tph and 250 tph respectively) for a woody-biomass-fired power facility, allowing the system to be operated less than full time during the week. The conveying and processing equipment capacities, yard layout, and storage quantities are considered reasonable.

The design truck dump rate of six trucks per hour per truck dumper (a total of 18 trucks per hour) is achievable but not probable to be maintained for any long period of time. A more realistic unload rate of four trucks per hour per truck dumper or total of 12 trucks per hour provides more than 300 tph (assuming 25-ton capacity per truck) in comparison to the full load requirement of 134 tph.

From discussions with plant personnel, the majority of OEM troughing idlers have been replaced (approximately 90 percent) due to bearing failure. Burns & McDonnell assumes that these issues are due to manufacturing defects and not overall system design issues. The problematic idlers have been found throughout the wood handling system and have been replaced with Joy Global brand sealed-for-life idlers. No subsequent issues have been reported.

Minor modifications to the spike roll systems at the unloading hoppers have improved unloading operations.

No other non-trivial issues with the material handling system were reported during the site visit. Burns & McDonnell believes the wood yard material handling system has been adequately designed to meet the Plant's biomass fuel needs for continuous full load operation and is in-line with margins at other facilities.

3.3.2 Ash Collection and Storage

Biomass fuel sources are inherently low in ash, and, therefore, small quantities are generated during operation. Nevertheless, a collection and storage system supplied by Allen-Sherman-Hoff is installed for both the bottom ash and fly ash generated by the BFB boiler and emissions control equipment. A vacuum pneumatic system collects fly ash from sections of the boiler and the baghouse hoppers. Fly ash is conveyed to a steel storage silo designed for a minimum of 4 days of storage at full load. Fly ash is discharged through a telescopic dry unloader and pug mill for disposal or sale by truck. Bottom ash, which is limited in quantity, is removed from the bottom of the boiler and collected in custom roll-off bins for periodic removal. ZLD system solids are also collected and hauled off-site by truck for disposal.

3.4 Water Supply and Treatment

Water supply is from two on-site wells, and recycled water from the City of Alachua. The wells can provide the entire water needs for the Project, however, reclaimed water is used as available. Well water and recycled water is stored in the 1,000,000-gallon raw water/fire water tank. A separate 50,000-gallon tank stores well water which is used for service water and for supply to the cycle makeup treatment system.

The cycle makeup treatment system provides high purity water to the plant steam cycle as makeup. The treatment process is a reverse osmosis ("RO")/electro-deionization ("EDI") configuration with two 100 percent trains. This treatment technology is considered proven and is typical for this application. The cycle makeup treatment system receives water from the well water storage tank. The initial treatment step utilizes ultrafiltration membranes to remove particulates from the well water. The RO then removes a significant portion of the ionic load, thereby reducing the burden on the EDI system, which polishes the processed water. The cycle makeup treatment, along with inlet ultrafiltration, is an appropriate means of producing demineralized water.

Potable water is obtained from a separate dedicated water well for treatment and distribution on-site.

3.5 Wastewater Treatment Systems

3.5.1 Process Wastewater

The Plant water systems are designed to minimize water use and maximize recycling and reuse using a ZLD system. The ZLD includes a brine concentrator and crystallizer. Process wastewater from the steam cycle makeup treatment system and steam cycle blowdown is routed to the cooling tower basin for reuse. Cooling tower blowdown is treated in the ZLD system with product water returned to the cooling tower. ZLD solids residue is produced in the crystallizer and disposed of in a landfill. The ZLD system to be a typical means to implement zero discharge requirements for power plants.

3.5.2 Potentially Oily Wastewater

All equipment and floor drains, potentially contaminated with oil, are routed through an oil/water separator prior to collection in the plant wastewater sump. The wastewater sump discharges to the cooling tower basin. This system is a typical means to remove oils that can be found in plant wastewater streams.

3.5.3 Sanitary Wastewater

The sanitary wastewater is collected via a network of gravity drain piping, and transferred to an on-site sewer lift station where waste water is pumped to the DGS sanitary system that discharges to the city sewer system.

3.6 Plant Electrical Systems

Power generated in the Plant's electric generator is transformed to 138 kV via a three-winding GSU transformer. The power from the GSU transformer is delivered to GRU's 138 kV transmission system that connects the facility to the Florida Reliability Coordinating Council, Inc ("FRCC") system.

The electrical system includes auxiliary electric systems, as well as high voltage systems to export power to GRU. The electrical equipment manufacturers, types, styles, and ratings are consistent with industry practice and appropriate for use in power plants.

3.6.1 Auxiliary Electric System

The auxiliary electric distribution system for the Plant consists of equipment that operates at nominal voltages of 4.16 kV, and 480 volts ("V"). The auxiliary electrical system design is considered appropriate and allows for the use of typical electrical distribution equipment.

The Facility does not have "black start" or "islanding mode operation" capabilities. The facility startup and backup power is back-fed from the 138-kV system through the station service transformer. If the 138-kV power system is not available, or power supply to the system is lost, a standby diesel engine generator provides standby power to supply housekeeping auxiliary loads. The auxiliary electric system is considered typical for a plant of this size and type.

3.6.2 Generator Step-Up Transformer

The Pennsylvania Transformer GSU transformer increases voltage provided by the STG to the 138-kV transmission system. The GSU transformer is a 13.8 kV to 138 kV, two-winding, ONAN/ONAF/ONAF, 104/138/173 MVA, three-phase, delta-wye, 60 Hz, 65 C rise transformer. The transformer is installed outdoors, and is an oil-filled type equipped with standard accessories and oil spill containment provisions.

3.6.3 Station Service (SS) Transformer

The SS transformer is also an outdoor type with standard accessories. The SS transformer supplies power for the plant auxiliary loads. The transformer is 138 kV to 4.16 kV, three-phase, 60 Hz, delta-wye 65 C rise transformer. The SS transformer and the GSU transformer are both connected to a 138-kV radial bus via their respective 138 kV breakers.

The SS transformer supplies power for auxiliary loads during startup, shutdown, and normal operations.

3.6.4 Direct Current and Critical Alternating Current Systems

All critical instrumentation, control, and monitoring circuits required for startup, on-line operation, shutdown, and off-line operation of the Facility are supplied either by a battery connected direct current ("DC") system or uninterruptible power supplies ("UPS").

The 125 V DC battery system is sized to supply a minimum of 8 hours for critical DC loads. Each 125 V DC battery charger is sized to fully recharge the batteries from a fully discharged condition in less than 15 hours while maintaining the continuous normal steady-state loads. Equipment sensitive to incoming power quality is fed from the UPS.

3.6.5 Grounding, Lighting, and Cathodic Protection Systems

Grounding, lightning, and cathodic protection systems are provided as needed within the Plant.

3.7 Transmission & Electrical Interconnection

The 138-kV plant switchyard is arranged in a radial bus configuration with two 138-kV circuit breakers. One 138-kV circuit breaker is connected to the high side of the GSU transformer. The other 138 kV circuit breaker is connected to the high side of the SS transformer. A 138-kV transmission line exits the 138-kV plant switchyard to terminate at GRU's 138-kV Switching Station at the point of interconnection.

The plant switchyard configuration is considered typical for application in a facility of this type and size. The switchyard equipment and materials were designed in accordance with applicable codes and standards. The switchyard equipment ratings are considered sufficient to facilitate full evacuation of output from the project.

The Project is interconnected to GRU's 138-kV Lines 21 and 22 via the 138 kV Switching Station. The interconnection point between the Project and GRU's 138-kV Switching Station is where the Project's jumper conductors connect with GRU's transmission line conductors on the Project's dead-end structure located adjacent to the Switching Station.

The Plant is responsible for ownership of the estimated 4,500 feet of single-circuit transmission line from the plant's 138-kV switchyard to the Project's dead-end structure located just outside of the GRU 138-kV Switching Station. This transmission line includes fiber-optic cable that is used for primary and redundant line relaying schemes.

3.8 Balance of Plant and Operation Systems

3.8.1 Fire Protection Considerations

The fire protection system for the Plant is designed in accordance with NFPA ("National Fire Protection Agency")850 "Recommended Practice for Fire Protection for Electric Generating Plants and High-Voltage Direct Current Converter Stations." The plant fire water supply system includes one 100 percent electric motor driven pump and one 100 percent diesel engine driven pump. Both pumps take suction from the 1 million gallon raw water storage tank, with 250,000 gallons dedicated to fire water service.

These pumps provide water to the fire protection system equipment. A jockey pump is used to maintain system pressure. Fire protection provisions are customary for a unit of this size and configuration.

3.8.2 Balance-of-Plant Mechanical Systems

The mechanical balance-of-plant ("BOP") systems are of conventional design and are provided with redundant capacity appropriate for power generation service. Installed spare capacity based on the percentage of the total plant requirement is presented in Table 3-1.

Table 3-3: BOP System Summary

System	Manufacturer	Equipment	Installed Capacity
Compressed Air	Atlas Copco	Compressors	2 x 100%
Circulating Water	Flowserve	Pumps	2 x 75%
Closed Cooling	Alfa Laval and Flowserve	Heat Exchangers and Pumps	2 x 100%
Condensate	Flowserve	Pumps	2 x 100%
Fire Protection	WW Gay	Pumps	2 x 100%
Boiler Feed	Flowserve	Pumps	2 x 100%

3.9 Instrumentation and Control System

The overall plant instrumentation and control system includes a distributed control system ("DCS") provided by Metso. The DCS is a microprocessor-based integrated control and data acquisition system providing control and monitoring of plant equipment from the central control room. The system consists of distributed processors and controllers, interconnected with all controller elements via a redundant switched Ethernet data highway.

All instrumentation and systems were designed to provide safe and reliable operation of the Plant in accordance with applicable codes and standards. In addition, the system was designed to follow all applicable National Electric Reliability Council ("NERC") and National Institute of Science and Technology ("NIST") cyber security requirements.

The instrumentation and control systems are appropriate for a plant of this type and size. The system should enable plant personnel to safely operate and monitor the performance of plant systems and components from the main control room.

4.0 OPERATIONS & MAINTENANCE PRACTICES

The following section summarizes the O&M practices for GREC.

4.1 Operating Philosophy

The Plant entered commercial operation in December 2013. The Plant has a PPA with GRU. Burns & McDonnell did not review the PPA as part of this Study, however, based on discussions with GREC, GRU will schedule the dispatch of the Plant under the PPA and receive both the capacity and energy from the Plant to meet its load obligations.

4.2 Plant Operations & Performance

The Plant is operated and maintained by NAES Corporation. Based on review of the data provided, the existing facility appears to be in good condition. The plant layout is typical for a facility of this type and size.

Plant personnel indicated there were two issues in the material handling system that have now been resolved: 1) hot spots within the fuel yard and 2) smoldering fuel within the hogger. The Plant implemented procedures to curtail the potential for hot spots within the fuel yard including better fuel segregation using a first-in, first-out policy and it now monitors pile temperatures twice per day. The fuel smoldering caused no damage to the equipment as it was contained within the hogger, but a lot of smoke was produced. The fire department was called because of the excessive amount of smoke in the building above the hogger (plant personnel are not trained in the use of self-contained breathing apparatus ("SCBA") and did not want to endanger anyone). There has been no additional fire suppression added since the plant completion. Following these procedural changes, Plant management indicated the Gainesville fire department inspector was satisfied with the wood yard based on the location of hydrants and that the insurance inspectors from AIG were also satisfied and have not made any requests for modifications.

Review of the documentation and discussions with plant personnel revealed that no abnormal conditions were detected that would prevent continued service.

4.2.1 Plant Staffing

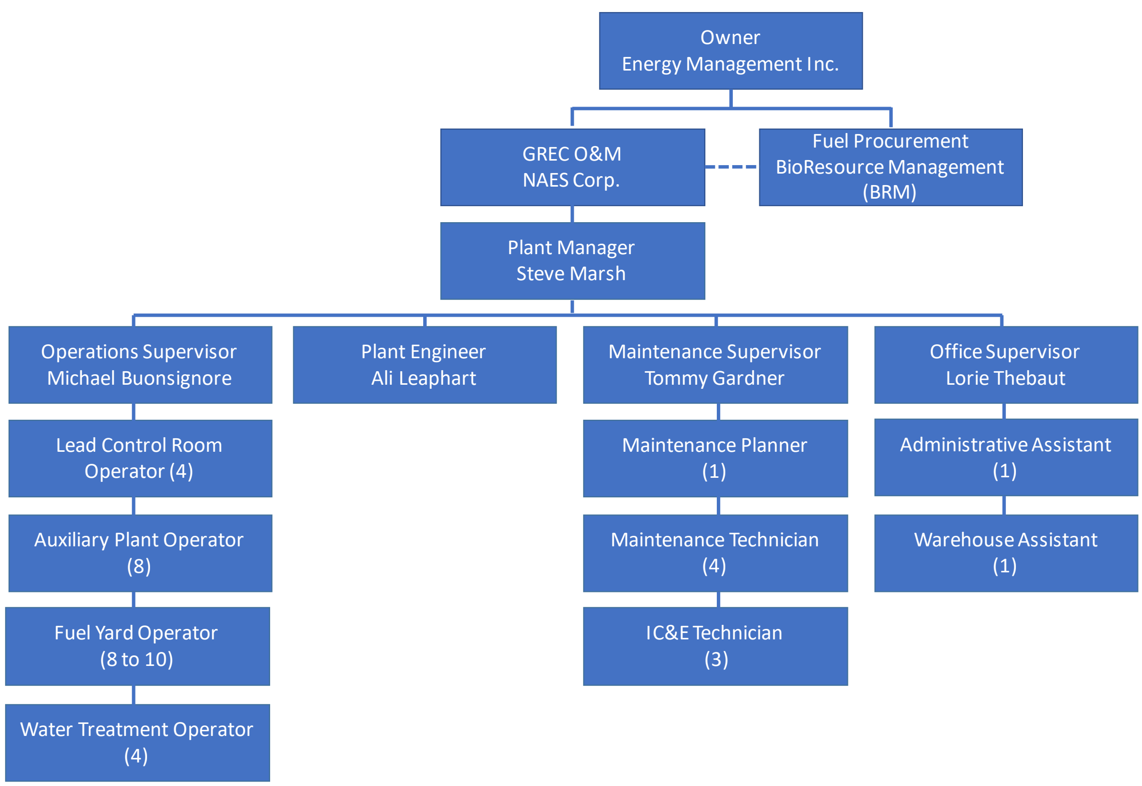
EMI has contracted operation and maintenance activities for both the Plant and fuel supply to NAES and BRM, respectively. A total of 39 employees currently make up the staff of NAES for GREC. BRM has a staff of four (4) employees dedicated to GREC. NAES provides all things necessary for the proper operation and maintenance of the Plant including day-to-day operation and maintenance, long-term maintenance planning, spare parts management, and other responsibilities required to maintain the Facility in proper working order.

In addition to the NAES staff, four employees are contracted through BRM for fuel management and procurement. The four employees consist of a Fuel Procurement Manager, Biomass Forester, Quality Control Technician, and Scale Attendant. BRM is charged with the following tasks:

- Development and maintenance of fuel supply chain, fuel delivery scheduling and preparation of fuel payments
- Operation of scales, ticketing system, and facilitation of truck dump operation.
- Fuel quality control oversight including in-house analysis of fuel moisture and ash content.
- Oversight of forest-sourced fuel Minimum Sustainability Standards ("MSS")
- Forest Stewardship Council ("FSC") Controlled Wood and Chain of Custody certification maintenance.

The organizational structure of the Plant is included in Figure 4-1. The overall staffing of the Facility appears to be similar to other biomass projects within the industry.

Figure 4-1: Gainesville Renewable Energy Center Organizational Structure

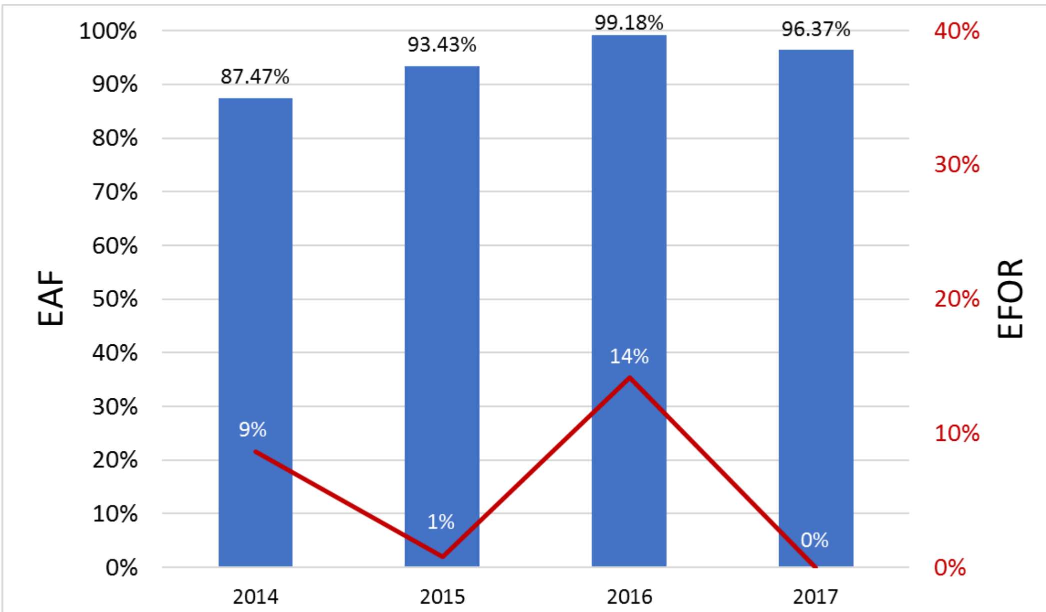


4.2.2 Plant Operating Statistics

Burns & McDonnell reviewed several key operating statistics to evaluate the overall reliability, utilization, and performance of the Plant.

Figure 4-2 presents key availability statistics for GREC from 2014 through 2017 regarding equivalent availability factor ("EAF") and equivalent forced outage rate ("EFOR").

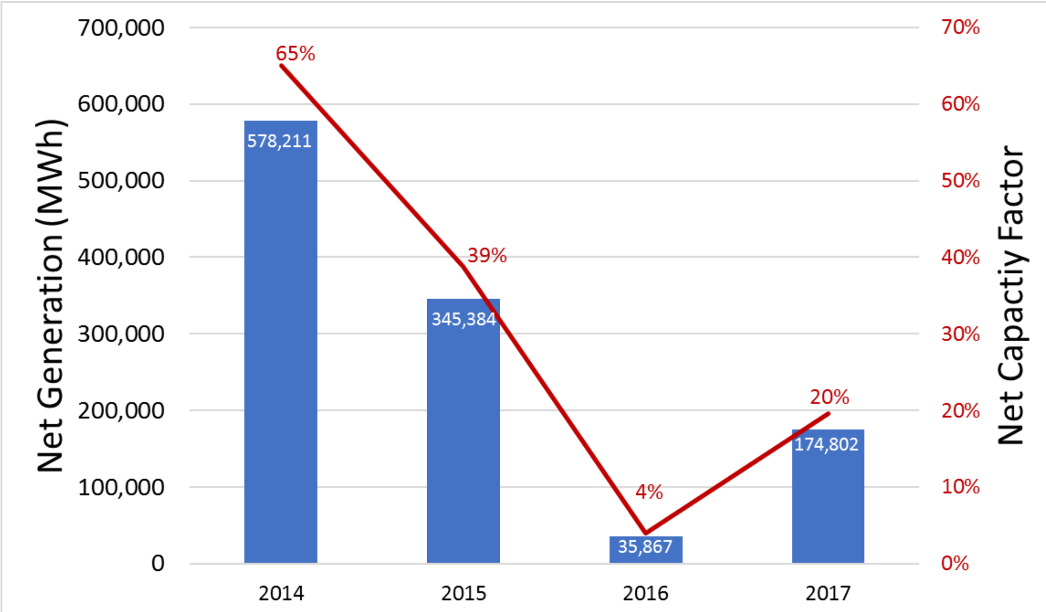
Figure 4-2: Plant Equivalent Availability Data for 2014 through 2017



As presented in Figure 4-2, both the EAF and EFOR were lower and higher, respectively, in 2014. However, this was the first year of operation and power plants typically experience lower reliability as the plants work through commissioning and problematic issues with the initiation of systems. The availability of the Facility dramatically increased from 2015 to 2017 and has been above 90 percent in each of these years. The EFOR in 2016 was elevated due to the low number of service hours for the unit since it was in a long-term layup status.

Figure 4-3 presents the net generation and net capacity factor for GREC from 2014 through 2017.

Figure 4-3: Plant Net Generation and Net Capacity Factor Data



The Plant was anticipated to operate as a baseload facility and have a high capacity factor when it was initially developed. However, the electric generation industry has seen a reduction in the price of wholesale power largely due to lower natural gas prices and more efficient combustion turbines. As such, the Plant has generated less energy recently and has been placed in long-term standby several times. The Plant was on stand-by for a significant portion of 2016. However, in 2017 the Facility was dispatched by GRU after the long stand-by period, and was able to start and reliably provide power after the extended layup.

From the NERC generating availability data system ("GADS"), solid-fuel facilities of similar size generally have availability factors in the 85 to 88 percent range, however this data includes facilities with a range of ages and technologies. Relative to other facilities of similar size, the Plant has experienced above average availability factors. Database research of similar biomass facilities in the southeastern U.S. indicted an average capacity factor of approximately 60 percent.

4.2.3 Thermal Performance

As previously discussed, the Plant has a PPA for electrical production which has cost and performance parameters associated with the delivery of electricity (the specific agreement was not reviewed as part of this Study). The performance of the Plant is important to assess its ability to provide efficient energy for GRU to meet its load obligations.

Burns & McDonnell reviewed the performance tests provided by GREC at the commissioning of the Facility and subsequent performance evaluations. The performance test, conducted by McHale & Associates Inc. ("McHale"), compared the guaranteed performance against the actual performance experienced during the test. After the performance test, McHale concluded that the results indicated that the plant performance passed for both electrical output and heat rate guarantees. Table 4-1 presents the results from the McHale report summarizing the Plant performance test at commissioning. While the corrected plant electrical output falls slightly short of the guaranteed plant electrical output, McHale indicated that it was within an acceptable range for the results accuracy.

Table 4-1: Summary of Plant Performance Test at Commissioning

Description	Units	Test Run 1	Test Run 2	Test Run 3	Average
Plant Electrical Output					
Guaranteed Plant Electrical Output	kW	101,520	101,520	101,520	101,520
Measured Plant Electrical Output	kW	102,884	102,916	102,943	102,915
Corrected Plant Electrical Output	**kW**	**101,325**	**101,431**	**101,037**	**101,264**
Margin from Guarantee	kW	-195	-89	-483	-256
	%	-0.19	-0.09	-0.48	-0.25
Plant Cycle Heat Rate					
Guaranteed Plant Cycle Heat Rate	Btu/kWh	12,559	12,559	12,559	12,559
Measured Plant Cycle Heat Rate	Btu/kWh	11,368	11,333	11,339	11,347
Corrected Plant Cycle Heat Rate	**Btu/kWh**	**11,857**	**11,860**	**11,834**	**11,850**
Margin from Guarantee	Btu/kWh	-702	-699	-725	-709
	%	-5.59	-5.56	-5.77	-5.64

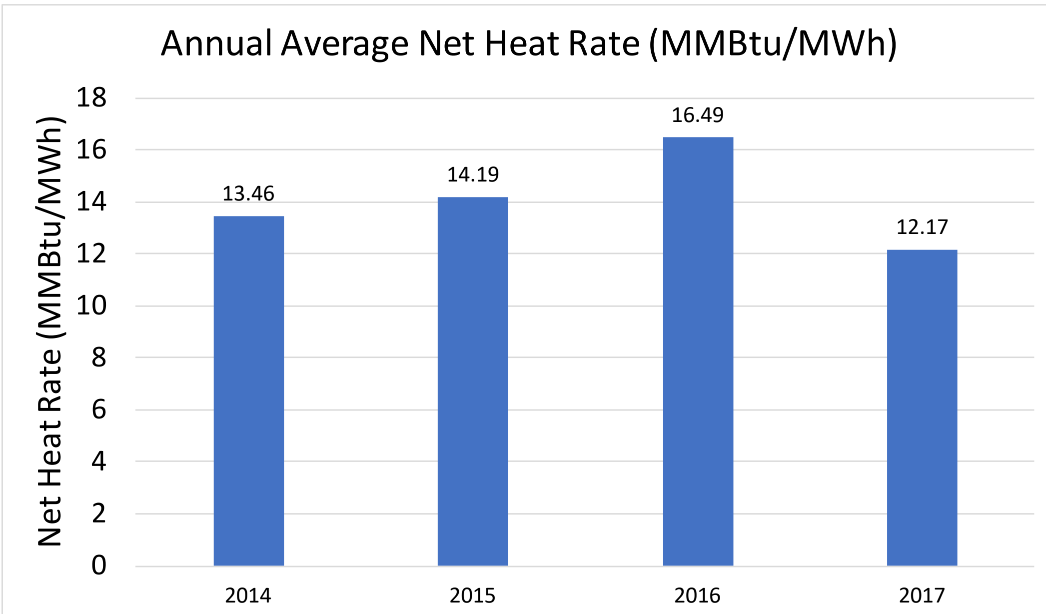
Note: The performance test was corrected using requirements associated with the original contract between GREC and the Plant engineer/construction contractor at the time of commissioning.

Most recently, GREC performed its dependable capacity claim test as defined within the PPA. This claim test was conducted on May 29, 2017. EMI reported the Facility operated at an average output of 103.05 MW over a 12-hour operating period. Based on both the claim test information and McHale's performance test, the Facility appears to be able to produce over 101.5 MW (net) as designed.

According to GREC, the minimum operating output for GREC is 70 MW as defined within the PPA. Burns & McDonnell inquired with the staff whether the Facility would have the ability to operate at a lower turndown point than is currently defined within the PPA. GREC indicated the Facility is limited to a technical turndown point of approximately 60 MW due to a backend temperature requirement located at the injection point of the SCR. The injection point of the SCR requires a minimum effective temperature of 375°F. If the unit is operating at less than approximately 60 MW, the backend temperature drops below 375°F and the SCR becomes ineffective. The installation of duct burners, heating coils, or an economizer bypass could be investigated as means to increase the overall temperature at lower load points, however this may require a modification to the air permit.

Figure 4-4 presents the average net plant heat from 2014 through 2017.

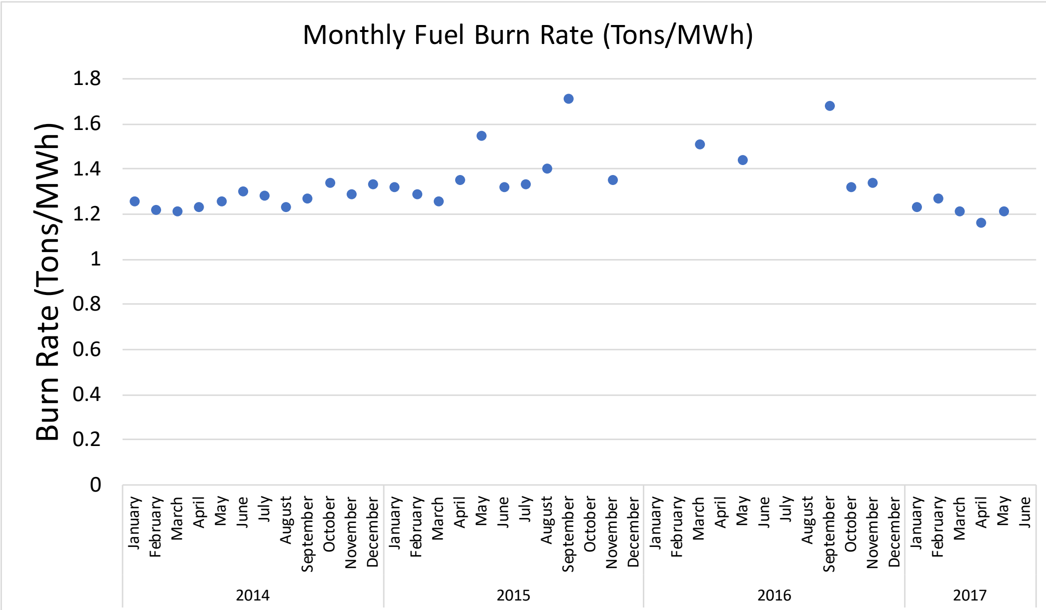
Figure 4-4: Plant Net Heat Rate for 2014 through 2017



As presented in Figure 4-4 the net heat rate for the Plant was considerably higher in 2016 compared to other years. This was due to the limited number of service hours in 2016. The overall heat rate fluctuated between 12 to 14 MMBtu/MWh for the other years of operation. Heat rates for biomass plants are heavily dependent on the fuel quality. The heat rate for the Facility appears to be similar to other biomass power plants of comparable size and age.

Figure 4-5 presents the monthly burn rate of fuel from 2014 through 2017 on a tons per generation (tons/MWh) basis.

Figure 4-5: Plant Fuel Burn Rate for 2014 through 2017



As presented in Figure 4-5, the burn rate of fuel measured as tons/MWh have typically fluctuated between 1.2 to 1.4 tons/MWh. In months where generation was limited, the overall burn rate was significantly higher, reflecting the similar trend to the overall heat rate.

4.3 Fuel Supply

During the site visit, BRM provided a presentation summarizing the fuel supply and management for GREC. GREC receives three main fuel types consisting of in-woods, urban, and mill residues. GREC has over 20 fuel suppliers and producers supplying the various fuel types. This includes seven (7) in-woods producers with the remainder consisting of urban producers. The average haul distance for in-woods fuel deliveries is between 50 to 55 miles, urban deliveries can be farther. Table 4-2 presents the typical fuel characteristics according to BRM.

Table 4-2: Typical Fuel Characteristics

Type	Moisture Content (%)	Ash Content (%)	Heat Content (Btu/dry lb)
In-woods	36% - 42%	< 2%	8,450
Urban	25% - 45%	2% - 10%	8,200
Mill residues (dry)	12%	< 1%	9,100
Mill residues (green)	45% - 52%	< 1%	9,100

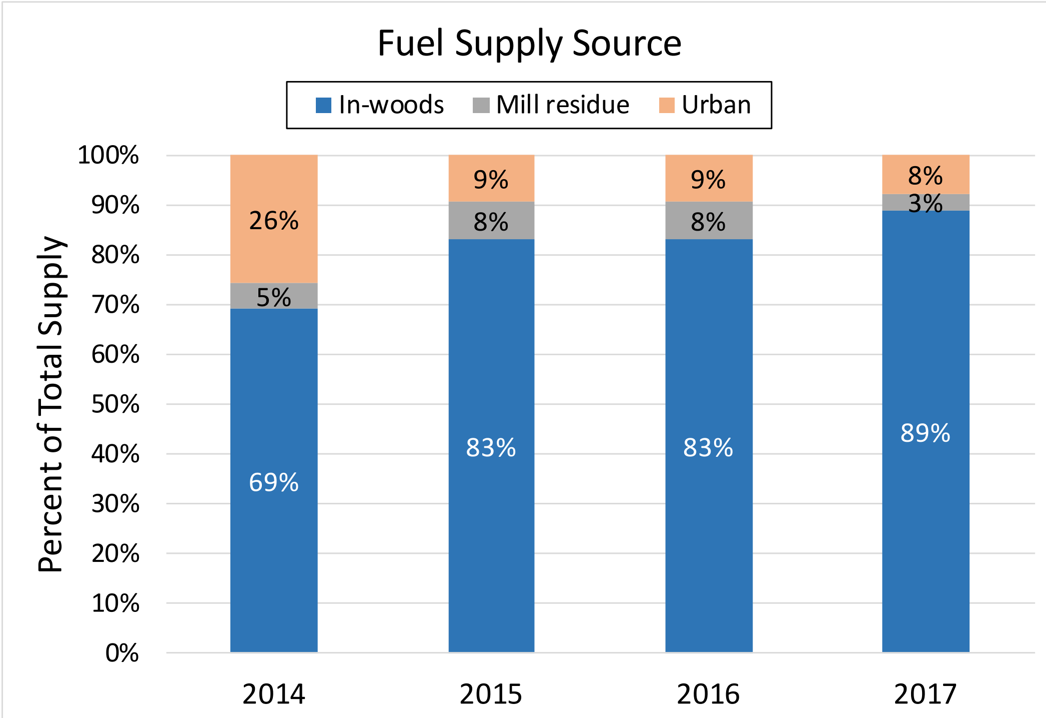
Overall, BRM estimates there is greater than 5 million acres of timberland within GREC's supply shed generating greater than 7 million tons of conventional roundwood products. Logging residues and other agricultural land management activity generates greater than 1 million tons of fuel wood. Urban resources account for approximately 700,000 tons of wood waste within an economic haul distance of approximately 50 miles. Mill residues generate approximately 2 million tons of potential fuel supply. While there are competing uses for these wood products, the supply of wood waste appears to be sufficient to maintain GREC's operation based on BRM's experience.[1] Table 4-3 and Figure 4-6 present the historical fuel sourcing for GREC. As illustrated in the table and figure, a large majority of the biomass fuel has historically come from in-woods resources.

Table 4-3: Historical Fuel Sourcing (tons)

Year	In-woods (tons)	Urban (tons)	Mill Residue (tons)	Total (tons)
2014	526,085	196,074	39,346	761,505
2015	394,738	44,536	36,134	475,408
2016	37,299	2,071	17,540	56,910
2017	181,819	15,904	6,837	204,560

[1] Burns & McDonnell did not complete an independent evaluation of the fuel supply availability in the area.

Figure 4-6: Historical Fuel Sourcing (tons)



BRM indicated that fuel delivery costs are a function of the type and quality of wood, distance hauled, diesel fuel prices, moisture content, and the overall dispatch characteristics of the Plant. BRM indicated that most fuel is procured on a dry weight basis (i.e. price is adjusted for moisture content). Additionally, fuel supply contracts typically contain adjusters for diesel fuel prices and are invoiced based on the distance that the fuel is hauled. Urban fuel suppliers typically have price adjusters for the percentage of ash content in the fuel. Table 4-4 presents the historical fuel costs for GREC.

Table 4-4: Historical Fuel Costs

	Category	Fuel Delivered (tons)	Moisture Content (%)	Fuel Delivered (dry tons)	Fuel Delivered (MMBtu)	Delivered Fuel Costs ($)	Delivered Fuel Cost ($/ton)	Delivered Fuel Cost ($/dry ton)	Delivered Fuel Cost ($/MMBtu)
2014	**2014**								
	In-woods	526,085	39%	319,694	5,402,834	$14,052,102	$26.71	$43.95	$2.60
	Mill residue	39,346	41%	23,348	424,932	$1,054,055	$26.79	$45.15	$2.48
	Urban	196,074	39%	119,293	1,956,404	$4,710,047	$24.02	$39.48	$2.41
	Total	761,505	39%	462,335	7,784,170	$19,816,204	$26.02	$42.86	$2.55
2015	**2015**								
	In-woods	394,738	39%	239,439	4,046,513	$10,423,918	$26.41	$43.53	$2.58
	Mill residue	36,134	39%	22,221	404,419	$964,620	$26.70	$43.41	$2.39
	Urban	44,536	38%	27,507	451,120	$1,060,456	$23.81	$38.55	$2.35
	Total	475,408	39%	289,167	4,902,052	$12,448,994	$26.19	$43.05	$2.54
2016	**2016**								
	In-woods	37,299	41%	21,880	369,780	$1,071,341	$28.72	$48.96	$2.90
	Mill residue	17,540	38%	10,958	199,431	$551,831	$31.46	$50.36	$2.77
	Urban	2,071	34%	1,360	22,296	$57,431	$27.73	$42.24	$2.58
	Total	56,910	40%	34,198	591,507	$1,680,602	$29.53	$49.14	$2.84
2017	**2017**								
	In-woods	181,819	40%	109,709	1,854,078	$5,227,153	$28.75	$47.65	$2.82
	Mill residue	6,837	26%	5,050	91,904	$195,480	$28.59	$38.71	$2.13
	Urban	15,904	31%	11,027	180,836	$356,237	$22.40	$32.31	$1.97
	Total	204,560	39%	125,785	2,126,818	$5,778,870	$28.25	$45.94	$2.72

4.4 Non-Fuel O&M Expenses

EMI provided a discussion of the O&M expenses that have been historically incurred and an overall summary budget for the Plant operating in both a long-term layup status and dispatched at baseload.

Table 4-5: O&M Budget Summary

Expense Category	2014	2015	2016
Fixed Expenses			
Labor/Staffing	$4,500,000	$4,600,000	$4,300,000
Fixed O&M	$2,480,000	$2,560,000	$1,400,000
Fuel Management	$839,000	$539,000	$405,000
Total Fixed Costs	**$7,819,000**	**$7,699,000**	**$6,105,000**
Total Fixed Costs ($/kW-yr)	**$77.03**	**$75.85**	**$60.15**
Variable Expenses			
Variable O&M	$2,880,000	$2,170,000	$966,000
Major Maintenance	$1,800,000	$1,700,000	$404,000
Total Variable Costs	**$4,680,000**	**$3,870,000**	**$1,370,000**
Total Variable Costs ($/MWh)	**$8.09**	**$11.20**	**$38.20**
Total Non-Fuel Expenses	**$12,499,000**	**$11,569,000**	**$7,475,000**

Note: Labor/Staffing presented above are considered fully burdened costs including payroll, employee benefit, and tax expenses.

The total fixed O&M costs for GREC are approximately $6 million to $8 million per year, which equates to approximately $60 to $75/kW-year when looked at on a per kW basis. This is slightly higher than would be expected for a biomass facility of this type and size. Database research of similar biomass facilities in the southeastern U.S. indicated an average total fixed O&M cost of approximately $32/kW-year is typical. However, GREC has significantly more equipment installed than the typical biomass facility consisting of the AQCS (SCR, baghouse, and DSI) and the ZLD system. This additional equipment further increases the costs associated with O&M.

The variable O&M costs for GREC are approximately $8/MWh to $11/MWh and are within the range of what would be expected for a biomass facility of this type. Database research of similar biomass facilities in the southeastern U.S. indicted a range of non-fuel variable O&M costs of approximately $8/MWh.

4.5 Major Maintenance

Burns & McDonnell reviewed the overall maintenance of the Facility and specifically some of the more critical major maintenance activities. The following major maintenance projects were completed since the Plant went into service.

- April/May 2015 Outage
    - Before the October 2014 outage, the boiler's tertiary superheater had experienced tube failures at the weld of the tube stub to the header. This was investigated and found to be a design issue. During the May 2015 outage, the header was replaced by Valmet under warranty, and as a result Valmet extended the warranty of the boiler until May 2016. GREC indicated there have been no further leaks.
    - A design issue was addressed by Siemens under warranty in the STG single combined steam admission and control valve, which was causing a control oil leak through the valve stem, and large oscillations in generator output at high power. There had been several outages before to replace the seal, which kept deteriorating and leaking. The permanent repair to the oil leak consisted of replacing the stem seal with a different design. GREC reported there have been no subsequent leaks.
    - The STG was experiencing a "flutter" in power output occurring between 90 MW and full load, with cyclical power output swings of about 1.5 MW (e.g., at 95 MW the power will swing between 93.5 MW and 96.5 MW). Obvious potential causes such as steam supply, vacuum or control oil variations, were investigated and eliminated as the root cause. The control valve was disassembled by Siemens during both the previous October

2014 outage and this outage, but no unusual conditions were found. According to plant personnel this is still occurring at a reduced 0.75 MW range, which Siemens has stated is within tolerance.

- In March 2017, Doble Engineering Company performed an electromagnetic interference diagnostic testing of the generator, isolated phase bus systems, and transformers, and found that the generator had questionable results, indicating that a problem is present or developing.
  - High radiated electromagnetic interference levels were noted at the generator connection box. They recommended inspecting the connections for looseness, proper assembly, and torque during the next scheduled maintenance period. According to EMI, during the May outage GREC inspected and re-torqued all connections in the connection box. Some bolts had not met torque requirements.
  - Very high radiated electromagnetic interference levels were noted from the lube oil piping at the turbine. Static discharges in lube oil systems can cause oxidation of the oil and result in oil breakdown and contamination. They recommended that an oil analysis be conducted, and if the oil is darkened and breaking down the source of the static discharges should be resolved. According to EMI, after investigation into the problem and discussions with other users of gas and steam turbines that experienced this type of static discharge a solution was found. GREC determined the resolution for this issue is using low static oil filters to eliminate the static discharge. GREC has been sampling turbine generator lube oil monthly and has not observed any degradation. GREC indicated that if degradation of oil quality is observed, then it plans to purchase and install electrostatic discharge resistant filters.
- June 2017 Outage
  - The GSU was tested by Electrical Reliability Services and found to have unacceptable moisture content in the oil for the type and class of transformer. They recommended oil resampling every three months. The Plant has been in long term layup since then. GREC did resample the oil in the GSU and the moisture level was acceptable. GREC indicated that regular oil sampling is part of its preventative maintenance program.
  - Seven flexible duct connections around the boiler begun to have cracks, with one leaking. All seven were replaced with higher quality material.
  - In other findings, batteries and catalyst were tested and found to be in good condition.

In addition to the major maintenance items above, the Plant has installed or modified a few other items of note:

- Due to frequent extended layups, a permanent nitrogen (N_2) generator for boiler blanketing during layups was installed during the fall outage of 2016 on Level 8 of the boiler.
- A noise reduction liner clad in stainless steel was installed in the stack shortly after plant startup to eliminate low frequency noise at a nearby residential subdivision.
- An odor control system was installed on the west side of the biomass fuel yard to help eliminate unpleasant odors.
- The Plant utilizes a "snow maker" style mist system to help control dust at the fuel yard.

4.6 Spare Parts Inventory

Burns & McDonnell reviewed and discussed the spare parts inventory with the plant staff. It appears the Plant has sufficient spare parts to maintain reliable operation. Major spare parts include a replacement belt for Conveyer 9 which feeds the power block and is considered the single point of failure for the material handling system. Additionally, GREC owns three large fan motors in dry storage in Jacksonville for the induced draft fan, primary air fan, and flue gas recirculation fan. Other major spares include rotary feeders, screws, impellers, valves, and bearings. Overall, the spare parts inventory has a cost of approximately $4 million.

5.0 KEY CONTRACTS AND AGREEMENTS

Burns & McDonnell reviewed several of the agreements that GREC currently has in place for operating the Plant. EMI indicated that the proposed structure of the sale was an asset sale, so some, if not all, of these agreements would be contingent on GRU and the other parties agreeing to assign the contracts from GREC to GRU. To the extent possible, Burns & McDonnell reviewed the contracts that GREC has in place; however, these may be subject to change based on negotiations between GRU and the counterparties. Furthermore, due to confidentiality concerns some of the specific pricing information was redacted within the agreements. However, the key terms were available for review against industry standards regarding technical/engineering operations.

5.1 Biomass Services and Fuel Management Agreement

GREC has a biomass services agreement in place with BioResource Management, Inc. Due to confidentiality concerns, Burns & McDonnell was provided a redacted version of the biomass services agreement, but key terms were reviewed. The following summarizes the key provisions of the biomass services and fuel management agreement.

- The initial term of the agreement is effective through December 31, 2019. Unless terminated in accordance with the agreement, the term will automatically renew for successive three-year periods.
- BRM shall supply the services related to the procurement, delivery and management of biomass used by GREC at the Facility.
- BRM is paid 1) a monthly management fee and 2) costs on a monthly basis for actual expenses incurred (without markup). The monthly management fee is adjusted each calendar year to movements in the Consumer Price Index.
- BRM does have the ability to receive an annual incentive payment as determined by a percentage of the difference between the fuel reimbursement amount less the actual fuel costs (the actual percentage was redacted).
- GREC or BRM may terminate the agreement with 60 days written notice prior to the end of a term (or extension).
- GREC may terminate the agreement 1) at any time during the term or extension for break or default by BRM or 2) upon providing 90 days prior written notice at any time.
- Either party may assign its rights and obligations under the agreement to an affiliate. Any party may assign its rights and obligations under the agreement to any entity acquiring all or substantially all of the business, assets, or outstanding voting interests. Neither party may assign

any of its rights or obligations under the agreement without the prior written consent of the other party.

- The agreement contains biomass specifications that require BRM to procure biomass 1) from specific resource categories, 2) with specific size parameters, and 3) reasonably free of incombustible material and unfluidized particles.
- BRM is to provide the following services:
  - Biomass delivery and receipt: Coordination of truck receiving and sampling
  - Biomass billing and payments: Maintain documentation of deliveries, generate invoices, facilitate timely and accounts payments to suppliers by coordinating with GREC, maintain contract requirements with suppliers, and communicate directly with suppliers regarding issues associated with deliveries, billings, or payments.
  - Biomass testing and analysis: Coordinate with operator of the Facility regarding testing of biomass samples for moisture content, particle size, and other appropriate protocol (such as ash content) and prepare and ship samples for testing.

5.2 Fuel Supply Agreements

GREC ("Buyer") has several biomass supply agreements in place with various suppliers ("Seller"). Due to confidentiality concerns, Burns & McDonnell was provided redacted versions of several fuel supply agreements. While specific costs and names were redacted, the overall general terms and conditions were reviewed against typical industry standards.

The following summarizes some the key provisions of the fuel supply agreements in general, some of the specific terms may vary slightly from contract to contract.

- Biomass shall be freight-on-board to the delivery point of Buyer. Seller shall pay all carting, storage and transportation costs incurred in the shipment including all freight, loading, insurance and other charges.
- Seller shall grant Buyer access to all processing sites for inspection. Buyer has the right to conduct both announced and unannounced inspections as it sees fit.
- Buyer, at its sole option, may choose to not compensate Seller for Biomass that does not comply with the terms and conditions. Buyer may also suspend deliveries from Seller for a period of no less than one year if seller is found to be in non-compliance with MSS.
- Buyer has the right to reject any and all deliveries that do not meet the specifications.
- Both Seller and Buyer may assign the agreement to an affiliate or acquiring entity with written consent from the other party, in which such consent shall not be unreasonably withheld.

- Seller shall provide 60-days written notice of, and reasons for, termination of the agreement.
- The agreements include exhibits regarding biomass specifications, best management practices requirements, and compensation.
- Biomass specifications
  - The agreements outline the type of biomass that is acceptable for delivery (depending on the supplier), including urban and/or forest produced biomass.
  - Moisture content will be determined for each delivered load in the Facility receiving bins by infrared measurements or other measurement methods as determined by the Buyer.
  - General/example specifications for urban biomass delivered to Buyer shall meet the following specifications:
    - Biomass shall contain less than 1/10th of 1 percent foreign material. Delivered loads with visible plastic film may be rejected.
    - Biomass shall be sized so that at least 95 percent by weight will pass through a 2.5-inch round screen; less than 1 percent by weight shall be greater than 8 inches in any dimension.
    - Biomass shall be sized so that no more than 18 percent by weight will pass through a 0.124-inch round screen.
    - Biomass shall not contain more than 6 percent ash content as determined on a dry weight basis, on average, for all deliveries each month; Delivered loads exceeding 12 percent ash on a dry weight basis may be rejected.
  - General/example specifications for forest produced biomass delivered to Buyer shall meet the following specifications:
    - Biomass shall contain less than 1/10th of 1 percent foreign material such as rock.
    - Biomass shall be sized so that at least 95 percent by weight will pass through a 2.5-inch round screen; no particles shall be greater than 6 inches in any dimension;
    - Biomass shall be sized so that no more than 25 percent by weight will pass through a 0.124-inch round screen
    - Biomass shall contain less than 2.5 percent to 4 percent (depending on the contract) ash content, including non-combustible inert materials, as determined on a dry weight basis.
- Best management practices and minimum sustainability standards
  - The agreements have an exhibit that address requirements for best management practices and the minimum sustainability standards for both urban and forest produced biomass.

    - Overall, the agreement entails that the suppliers must meet many requirements regarding the procurement of biomass resources including, but not limited to, environmental, legal, planting, harvesting, and record keeping practices.
- Compensation
    - The biomass price consists of the following components:
        - Cut and process price
            - Stumpage allowance ($ per dry ton)
            - Process allowance ($ per dry ton)
            - Off-road fuel allowance (gallons fuel per dry ton)
        - Freight price
            - Non-fuel freight allowance ($ per loaded mile)
            - On-road fuel allowance (gallons fuel per loaded mile)
    - Fuel allowances are determined each calendar month and adjusted based on the U.S. Energy Information Administration's East Coast Lower Atlantic Region.
    - Stumpage allowance is adjusted by a stumpage index which is defined as the quarterly percent change in the average price of hardwood and softwood pulpwood stumpage prices as reported by an index mutually agreed by the Seller and Buyer (the specific index was redacted).
    - Compensation is based on dry tons, therefore the Sellers are incentivized to deliver lower moisture biomass.

5.3 Reclaimed Water Supply Memorandum of Understanding

A Reclaimed Water Supply Memorandum of Understanding ("MOU") was executed by and between GREC, the City of Gainesville, Florida (d/b/a GRU), the City of Alachua ("City"), and the Suwannee River Water Management District (individually known as "Party" or collectively known as the "Parties"). The MOU implements the terms and conditions that the Parties will use to promote the use of Reclaimed Water at the Facility and thereby reduce the use of groundwater. As a Party to the MOU, it is anticipated that GRU will be assigned and responsible for GREC's portion of the MOU.

Key terms of the MOU are as follows:

- Several terms of the MOU were applicable to the Plant while it was under development and/or construction, including the following:
    - The City will use best efforts to identify and obtain state, federal, and other grants to pay the capital costs associated with the construction of the proposed water pipeline that will connect

the City's Reclaimed Water system to the Facility. Any costs not covered by grants will be paid for by GREC and/or GRU.

- The City's proposed pipeline routing shall be determined by the City (with consultation by GREC and GRU) and the selected routing shall be the lowest cost alternative when evaluated considering the anticipated capital, operating, maintenance, permitting, and other costs associated with the construction and operation of the City's proposed pipeline.
- The City shall construct, own, operate, and maintain the pipeline needed to transport the Reclaimed Water to the Point of Interconnection.

- The City has the right to provide its Reclaimed Water to the City's other customers and has the right to determine when and how much of the City's Reclaimed Water will be available to the City.
- Prior to GREC using groundwater, GREC shall use the maximum amount of Reclaimed Water feasible.
- GREC LLC shall pay to the City a reasonable usage charge per thousand gallons ("kgal") for the Reclaimed Water, which shall be the total of the following.
  - The actual or mutually agreed upon estimate of the cost incurred by the City to operate and maintain the facilities required to provide the Reclaimed Water to the Energy Center.
  - The actual or mutually agreed upon estimate of the cost incurred by the City to maintain, repair, renew, and replace, as necessary, the facilities used to provide the City's Reclaimed Water to the Energy Center.
  - The City's usual and customary overhead expense percentage, which shall include the transfer of funds from the City's Wastewater Collection and Treatment Division, Public Services Department to the City's General Fund, and which shall be applied as a percentage to the sum of items.
- The City expects to be able to provide approximately 0.4 to 0.6 million gallons per day ("MGD") of the approximate 1.4 MGD the Facility will require.
- Since the usage charge is not specifically defined or limited by the Agreement, GREC does have some financial risk for the cost of the reclaimed water, particularly since they are obligated to purchase the reclaimed water. However, the Parties have agreed to review the usage calculations and use an independent engineer to evaluate disputes.
- As part of the permitting process, GRU agreed to decrease their groundwater withdrawals by an equivalent amount to GREC's groundwater withdrawals.
- The American Renewables personnel indicated that GRU has agreed to this provision, and could reduce their water withdrawals as needed.

- The MOU shall remain in effect for the life of the Plant. The MOU also may be amended or renewed and extended with the written consent of the Parties.

5.4 Operations & Maintenance Agreement

GREC ("Owner") and NAES Corporation ("Operator") have a contract for the operation and maintenance of a biomass-fired power production facility dated June 14, 2011. EMI provided a redacted version of the agreement due to confidentiality concerns. The following provides a summary of the key provisions of the agreement.

- The Operator provides all things necessary for the proper operation and maintenance of the Plant under the O&M Agreement.
- The term of the agreement is six years from the date of commercial operation. The first contract year began on the date of commercial operation and ended on December 31 of the same year. Each consecutive contract year begins on January 1 and ends on December 31. From that point on, the contract term automatically renews every five years, unless written notice is given six months prior to the end of a term.
- The O&M Agreement may be terminated at any time due to an event of default by either party. The Owner may terminate the agreement for convenience at any time with 90 days' written notice to Operator.
- The Operator receives a base Management Fee as well as a Bonus Fee from the Owner. The Operator is also subject to pay Liquidated Damages to the Owner. The exact amount of each fee, as well as the Bonus and Damages cap has been redacted from the document.
- The Operator is reimbursed for all Direct Costs reasonably incurred in the performance of the O&M Services, in addition to the Base Fee and any Bonus Fees. These include Project Work Force compensation; materials, supplies, consumables, and other expenditures relating to the operating, and maintenance costs of the Project, including the costs of all parts and equipment; services provided by subcontractors and many administrative costs, such as accounting fees and other professional services required to comply with this agreement.
- In addition to the payments mentioned above, the Owner is subject to a late-fee, according to the "Late Payment Rate" which means, in relation to any period for which a late payment charge may be incurred under this Agreement, the prime rate as announced from time to time by the Bank of America plus two percent calculated based on a 365-day year and compounded monthly

Based on a review of the O&M Agreement, Burns & McDonnell concludes the following with respect to future risks/issues:

- The O&M Agreement contains standard industry terms and conditions.
- The Plant does not appear to have any technical limitations that would prevent it from meeting the requirements of the O&M Agreement.
- The Operator is a qualified third-party operator of power generation facilities.
- The Management and Bonus Fees, although redacted for this review, appear to be clearly defined.
- The performance criteria required are clearly defined within the Appendices of the O&M contract.

5.5 Power Purchase Agreement

GRU and GREC have a PPA in place. Burns & McDonnell did not review the PPA as it was outside of the scope of work for this Study.

5.6 Interconnection Agreement

GREC and GRU indicated that the Plant currently has an interconnection agreement with GRU. It is assumed that after the sale of the Facility, GRU would control the interconnection agreement. Burns & McDonnell did not review the interconnection agreement as it was outside the scope of work for this Study.

5.7 Lease Agreement

GREC and GRU indicated that GREC currently has a lease agreement with the City of Gainesville (d/b/a GRU). It is assumed that after the sale of the Facility, GRU would control the lease agreement. Burns & McDonnell did not review the lease agreement as it was outside the scope of work for this Study.

5.8 Natural Gas Supply

GREC and GRU indicated that GREC currently has an agreement to receive natural gas supply from GRU. It is assumed that after the sale of the Facility, GRU would control the natural gas supply. Burns & McDonnell did not review the natural gas supply agreement as it was outside the scope of work for this Study.

6.0 ENVIRONMENTAL REVIEW

Environmental studies, applications, and permit documents were reviewed, all or in part, as provided by GREC. No fatal flaws were identified. Owners and operators should make themselves aware of all permit conditions, paying particular attention to required notifications and expiration dates.

GREC prepared and submitted a Site Certificate Application ("SCA") to the Florida Department of Environmental Protection to obtain certification of the construction and operation of the power plant as required under the Florida Electrical Power Plant Siting Act. The Siting Board (Governor and Cabinet) approved certification on December 7, 2010, and the final order was issued on December 15, 2010. Conditions of Certification ("COC") PA 09-55 contain both general conditions and specific conditions, which are reviewed below. In addition, the Facility is currently subject to multiple air, water and other environmental regulations and/or permits. According to the plant personnel, the Facility is in material compliance with the current environmental permits. Since the Facility is relatively new, the environmental controls are also relatively new. As a result, the Facility appears to have a low likelihood of near term additional environmental costs. This analysis assumes that the current attributes of the fuel are not significantly changed in the future and the unit operating profile is similar to the past. The following sections describe the specific environmental topics analyzed as part of this Study.

6.1 Air Quality

The BFB boiler has a maximum steam production rate of 930,000 pounds per hour. Other emission units at the Facility include: biomass fuel delivery, preparation, storage, and handling; ash handling, storage, and shipment equipment; a mechanical draft cooling tower; a 1,220-horsepower ("hp") emergency generator engine; a 315-hp emergency fire pump engine; and an alkaline sorbent storage silo. The facility is an electrical services plant categorized under Standard Industrial Classification No. 4911. The initial construction of GREC was issued the Prevention of Significant Deterioration ("PSD") permit # 0010131-001-AC on December 28, 2010.

Based on the initial Title V air operation permit received February 11, 2014, the Facility is regulated as a major source of hazardous air pollutants ("HAP"), because it is located at a major source of HAP (i.e., GRU DGS). The existing facility is a PSD major source of air pollutants in accordance with Rule 62-212.400, Florida Administrative Code ("F.A.C.")

Currently, DGS and GREC have separate Title V permits but are considered a single source for permitting purposes. If GRU purchases GREC, the next Title V renewal or modification for DGS and for GREC will roll both facilities into a single Title V permit.

GREC SO_2 and NOx emissions were offset by permanent and enforceable reductions required at the contiguous GRU DGS following installation and startup of new air pollution control systems in 2009.

6.1.1 Prevention of Significant Deterioration

The initial construction of GREC was issued PSD permit # 0010131-001-AC on December 28, 2010. This permit was found on line at the Florida Department of Environmental Protection's ("FDEP") website and not in the data room. The permit was incorporated into the latest Title V permit, #0010131-006-AV.

6.1.2 Limits and Controls

Table 6-1 summarizes the emission units and their requirements. Table 6-2 summarizes the limits for the BFB boiler.

Excess emissions are limited as follows:

- Cold startup limited to 19 hours
- Warm/hot startup limited to 15 hours
- Shutdown limited to 3 hours in any 24-hour period
- The combined duration of excess emissions during cold startup, warm/hot startup, and shutdown is limited to 340 hours during any consecutive 12-month period.

Table 6-1: Emission Units and Air Permit Requirements

Emission Unit Number	Emission Unit Description	Requirements
001	Biomass fuel delivery, preparation, storage and handling	• Can operate continuously (8,760 hours/year). • The maximum designed hourly biomass processing rate is 600 tons per hour (tph) with a maximum designed yearly rate of 1,395,030 tons per year (tpy) • Specifically prohibited from accepting biomass in the form of construction and demolition debris. • Burns clean woody biomass • Conveyors must be enclosed where practical • A baghouse is used to control particulate matter ("PM") emissions from the screen/hog building. • A screw conveyor is installed to take the PM collected in the baghouse to the conveyor taking the biomass fuel to the biomass fuel handling and storage system. • Bin vent filters is used to control PM emissions from the metering bins for the BFB boiler • Facility must follow Best Management Practices (BMP) plan to minimize fugitive dust from biomass handling and fugitive dust emissions from the Plant's paved roadways and gravel areas • 10% opacity limit for drop and transfer points. 5% opacity limit from screen/hog building baghouse and bin vent filters on metering bins. Monitoring is via Method 9
002	Nominal net 100 MW BFB, biomass fueled boiler	• Natural gas is used as a startup fuel for the boiler. • The maximum heat input capacity is 1,358 million British thermal units per hour (MMBtu) per hour (4-hour average basis). • The maximum steam production capability is 930,000 pounds per hour (lb/hr). • The maximum heat input capacity using natural gas is 341 MMBtu/hr during startup. • Subject to New Source Performance Standard (NSPS) Subpart Da and National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart DDDDD • The hours of operation of this emission unit are not restricted (8,760 hours/year). • Controls: baghouse, (SCR), in dust sorbent injection system for sulfur dioxide (SO_2) removal • SCR uses 19% ammonia; 15,000-gallon tank • Monitoring includes: bag leak detection; NOx, SO_2, and carbon monoxide (CO) continuous emissions monitoring system ("CEMS"); opacity continuous opacity monitoring system ("COMS"; pressure drop detection • Subject to Acid Rain, Clean Air Interstate Rule (CAIR), and the Transport Rule Trading program

Emission Unit Number	Emission Unit Description	Requirements
003	Ash handling, storage, and shipment	• The design maximum process throughput rates are 27,594 tpy of fly ash and 13,140 tpy of bottom ash • The overall ash handling, storage and shipment system has a maximum annual design transfer rate of 40,734 tpy. • Controlled by enclosure and bin vents/baghouses • The hours of operation of this emissions unit are not limited (i.e., unrestricted at 8,760 hours per year). • Opacity limits vary by equipment, monitored by Method 9 annual compliance test • Method 5 test required annually on fly ash silo • PM emissions from the baghouse of the fly ash silo shall not exceed 0.015 grains per dry standard cubic feet (gr/dscf).
004	Mechanical draft cooling tower	*Unregulated*
005	One emergency generator diesel engine	• Maximum design engine output rating of 315 hp (235 kilowatts [kW]) • NSPS Subpart IIII (Tier II emission limits) • Compliance with NESHAP Subpart ZZZZ met by complying with NSPS Subpart IIII • 1,000-gallon fuel storage tank • Ultra-low sulfur diesel fuel • The emergency generator diesel engine may operate up to 100 hours per year for maintenance and testing purposes. There is no time limit on the use of emergency stationary internal combustion engines (ICE) in emergency situations.
006	315-hp emergency fire pump engine	• Maximum design engine output rating of 1,220 hp (910 kW) • NSPS Subpart IIII (Tier II emission limits) • Compliance with NESHAP Subpart ZZZZ met by complying with NSPS Subpart IIII • Ultra-low sulfur diesel fuel • The emergency generator diesel engine may operate up to 100 hours per year for maintenance and testing purposes. There is no time limit on the use of emergency stationary ICE in emergency situations.
007	Alkaline sorbent storage silo	• Controlled by bin vent filter • The hours of operation of this emission unit are not restricted (8,760 hours/year). • PM emission rate of 0.01 gr/dscf and opacity limited to 5% • Annual stack tests required (Method 5, 5B, 17, 9, 201, 201A)

Table 6-2: BFB Boiler Limits

Parameter	Limit	Basis	Compliance
NO_x[a]	1.0 pound per megawatt hour (lb/MW-hr) (gross basis)	NSPS Subpart Da	30-boiler operating day rolling average basis by CEMS
	0.070 lb/MMBtu	Applicant Request	30-boiler operating day rolling average basis by CEMS
	416.4 tpy	Emission Cap	12-month, rolled monthly by CEMS
SO_2[b]	1.4 lb/MW-hr (gross basis)	NSPS Subpart Da	30-boiler operating day rolling average basis by CEMS
	0.029 lb/MMBtu	Applicant's Request	24-hour rolling by CEMS
	170.7 tpy	Emission Cap	12-month, rolled monthly by CEMS
SAM[c]	1.4 lb/hr	Rule 62-4.070(3), F.A.C.	Annual Stack Test
CO[d]	0.08 lb/MMBtu	BACT	30-day rolling by CEMS
	310 ppmvd @3% oxygen (O_2)	NESHAP Subpart DDDDD	Annual Stack Test
HCl[e,f]	2.22 lb/hr	Applicant's Request	Stack Tests as Required by NESHAP Subpart DDDDD
	0.022 lb/MMBtu	NESHAP Subpart DDDDD	Annual Stack Test
HF[e]	2.22 lb/hr	Applicant's Request	Stack Tests as Required by NESHAP Subpart DDDDD
Mercury[f]	8.0×10^{-7} lb/MMBtu	NESHAP Subpart DDDDD	Annual Stack Test
PM/PM_{10} (filterable)[g]	0.0098 lb/MMBtu	BACT, NSPS Subpart Da NESHAP Subpart DDDDD	6-minute blocks by COMS
Visible Emissions[h]	10% Opacity (20% once/hr)	BACT	Annual Stack Test
VOC	0.009 lb/MMBtu	BACT	Annual Stack Test
NH_3 Slip[i]	10 ppmvd @ 7% O2	Rule 62-210.650, F.A.C. Rule 62-4.070(3), F.A.C.	4-hour average, measured by the steam flow meter
Steam Production Rate	930,000 lb/hr	Rule 62-210.200 (PTE), F.A.C.	30-boiler operating day rolling average basis by CEMS

Notes for Table 6-2:

a. Emission cap for NOx ensures that GREC will not trigger PSD for this pollutant.
b. Emission cap for SO_2 ensures that GREC will not trigger PSD for this pollutant.
c. Sulfuric acid mist ("SAM") mass rate emission limit provides reasonable assurance that annual emissions will be less than 7 tpy and PSD is not triggered for this pollutant.
d. The NESHAP limit of 310 parts per million by volume dry ("ppmvd") @3% O_2 applies from the initial operation of the boiler.
e. The hourly limits for HF and HCl are imposed at the Applicant's request. Compliance will be demonstrated with annual stack tests.
f. Hg and HCl limits for Subpart DDDDD compliance. However, if the performance tests for at least two consecutive years show that the emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 or 11 through 13 of Subpart DDDDD, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the BFB boiler or air pollution control equipment that could increase emissions, GREC may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test.
g. Filterable fraction as measured by EPA Method 5. The Subpart DDDDD 0.0098 lb/MMBtu limit will ensures compliance with the previous BACT and NSPS Subpart Da limit of 0.015 lb/MMBtu.
h. During startups, shutdowns and malfunction the following limits apply: 20% opacity (6-minute blocks) except for one 6-minute block per hour of 27%. Meeting this opacity standard provides assurance that the NSPS Subpart Da standard of no greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity is met.
i. Ammonia ("NH_3") slip in parts per million by dry volume at 7% oxygen (ppmvd @ 7% O_2).

6.1.3 Monitoring and Testing

The BFB boiler stack shall be tested during each federal fiscal year (October 1st to September 30th) to demonstrate compliance with the emission standards for NH_3 slip, filterable PM, volatile organic compounds ("VOC"), SAM, HCl (in units of lb/hr and lb/MMBtu), HF (in units of lb/hr), and opacity. Compliance stack tests for HCl (in units of lb/MMBtu) shall be conducted as required by NESHAPs Subpart DDDDD. Tests shall be conducted between 90 and 100 percent of the maximum permitted capacity when firing woody biomass fuel. CEMS data for CO, NOx and SO_2 along with COMS data for opacity shall be reported for each run of the required tests for NH_3, VOC, SAM, and PM. The BFB boiler was required to have initial stack tests conducted for NH_3, filterable PM (F), VOC, SAM, opacity, HCl, and HF. The FDEP may require the permittee to repeat some or all of these initial stack tests after major replacement or major repair of any air pollution control or process equipment.

Annual stack tests are required for fly ash silo and alkaline sorbent storage silo.

The Title V permit has an "Appendix BMP" which lists the Best Management Practices ("BMP") plan for minimization of fugitive dust, storage pile management and fire prevention. This document was found online and not provided in the data room.

Performance tests were completed from March 22 to 24, 2017. The test program was used to determine the compliance status of Woody Biomass-fueled BFB Boiler regarding its emissions limitations and standards outlined in Air Construction Permit 0010131-006-AV and Industrial Boiler Maximum

Achievable Control Technology ("IB MACT") standards, 40CFR63, Subpart DDDDD. Results were well below all limits. A relative accuracy test audit ("RATA") was also completed from March 21 to 22, 2017 with passing results.

6.1.4 National Ambient Air Quality Standards ("NAAQS")

The draft "Technical Evaluation & Preliminary Determination" was found on line and not in the data room. This document discusses the air dispersion modeling that was conducted for the initial construction of the Facility. PM_{10} and carbon monoxide ("CO") were modeled; PM_{10} was used as a surrogate for $PM_{2.5}$. CO impacts were below the significance level. PM10 impacts were in compliance with the NAAQS and PSD Increments. Impacts on the nearby Class I areas were below the allowable increment.

$PM_{2.5}$ modeling may be required in the future if additional construction is undertaken at this or another nearby facility. Additionally, 1-hour SO_2 modeling may be required for NAAQS demonstration purposes.

6.1.5 Industrial Boiler MACT

The limits imposed on the BFB Boiler by the IB MACT (NESHAP Subpart DDDDD) are included in Table 6-2.

6.1.6 Greenhouse Gas Emissions

Greenhouse gases are not expected to be an issue for biomass facilities.

6.1.7 Appeals

The permit issued in December 2010 was appealed in January 2011. A settlement was reached (March 4, 2011) with the appellants which required further conditions as outlined below. The settlement agreement states that if the DEP fails to put these requirements into the PSD permit within 45 days, the conditions are still effective. Condition 1.24 states that GREC shall request the permit modifications outlined in the settlement to the FDEP within 30 days of the effective date. Below is detailed information about the settlement.

6.1.7.1 Settlement Agreement

On March 4, 2011, GREC entered into a settlement agreement with petitioners that had been challenging the permit issuance for Facility. The agreement required:

- Allows the Alachua County Environmental Protection Division ("ACEPD") access to CEMS reports and to inspect the facility.

- Further inspections by the ACEPD for this facility, including surveys for wildlife, inspection of the biomass and other environmental reasons for inspections.
- GREC must give $25,000 each year for the next six years (after formal Notice to Proceed construction) to the ACEPD to assist in compensating the department for the inspections that they will be performing on the Facility.
- GREC will comply with any MACT that is issued for this facility, including an IB MACT or electrical generating unit MACT.
- GREC must pay the ACEPD for any enforcement case, on top of any formal fine imposed by the DEP. In addition, GREC must give money to a non-profit organization chosen by the appellants if an enforcement case is drawn by the DEP.
- A dioxin limit of 0.15 ng/dscm at 7 percent oxygen ("O_2") shall be included in the PSD permit. The PSD permit has yet to be modified. An initial stack test and annual stack tests for dioxins are also required by this agreement.
- Annual stack tests for $PM_{2.5}$ are required. This has yet to be included in the PSD permit. GREC must comply with any "new requirements" for $PM_{2.5}$. The requirement goes on to state that this includes "any applicable regulation that requires a BACT analysis". As stated previously, the EPA also commented on the absence of $PM_{2.5}$ in the permit. At this point, a $PM_{2.5}$ BACT analysis would be essentially the same as PM_{10} (and NOx and SO_2, precursors to $PM_{2.5}$).
- Request that FDEP modify the PSD permit to incorporate the conditions of the settlement agreement

According to GREC management, GREC requested, but FDEP refused to modify the permit to include the settlement agreement since the settlement was a private agreement. Compliance with the settlement cannot be determined based on the materials provided in the data room. Whether the settlement is void upon sale of GREC assets to GRU is a legal matter beyond the scope of this evaluation and would require further evaluation by an attorney.

6.1.8 Compliance Status

In 2014, there were compliance issues with the short-term NOx limit of 0.070 lb/MMBtu (24-hr average). This limit was not set by best available control technology (BACT); it was set to limit NOx emissions to a cap of 416.4 tpy. The Facility currently meets the tpy limit. The exceedances were due to catalyst warm up temperatures. A February 18, 2016 letter from FDEP states that compliance was achieved. There were also opacity compliance issues that occurred during boiler startup. These compliance issues were resolved through work practices that were developed for the startup procedure. GREC indicated that these procedures would transfer with the asset.

Minor issues were reported in 2015. No compliance issues were reported in 2016. Excess emissions reports for five quarters were provided (1Q2016 through 1Q2017). Less than 30 hours per quarter were out of compliance due to testing or startup/shutdown.

6.2 COC Specific Conditions

The COC detailed specific conditions that must be addressed prior to construction, or for on-going activities. Many of the activities required obtaining a permit specific to the condition. The conditions are generally outlined below. Many of the permits were not available for review.

Topics generally covered in the COC conditions include, but are not limited to, the following:

- Potable Water Wells
- Industrial Wastewater Treatment Facilities
- Solid Wastes
- Fly Ash
- Wetlands
- Highway Access
- Air Space
- Protected Species
- Gopher Tortoise
- Wading Birds
- Groundwater Withdrawal
- Reclaimed Water
- Local Permits

Burns & McDonnell was not able to verify if all permits were obtained or if all conditions were satisfied. The specific permits and topics that were reviewed and verified are outlined in the following sections.

6.3 Water Resources

GREC uses reclaimed water from the City of Alachua Wastewater Treatment Plant ("WWTP") and groundwater from two on-site wells to meet the Plant's process water needs. According to the Reclaimed Water Supply MOU between GREC, GRU, the City of Alachua, and the Suwannee River Water

Management District, GREC agreed to take all reclaimed water provided from the WWTP to reduce the amount of groundwater utilized by the Plant. The WWTP can provide approximately 0.4 to 0.6 MGD of the approximately 1.4 MGD needed for Plant operation; however, the MOU grants the WWTP the right to provide reclaimed water to its other customers and to determine when and how much reclaimed water will be available to GREC. The remaining process water need is provided by the on-site wells, which are capable of providing 100 percent of the process water required for plant operation. Pumping rate data were not provided for reclaimed water or groundwater to determine actual water usage rates.

Groundwater and reclaimed water are stored in a 1,000,000-gallon tank for cooling water makeup and fire protection. This storage volume provides for approximately 12 hours of cooling tower makeup under maximum water usage. A standpipe is installed in the tank to prevent the water level from dropping below the 250,000 gallons reserved for fire protection. A separate 50,000-gallon tank stores well water used for service water and supply to the cycle makeup treatment system.

Potable water is provided by a third on-site well.

6.4 Wastewater Discharges

GREC operates a ZLD system; therefore, no process wastewaters are discharged from the site.

6.5 Storm Water Discharges

Three primary stormwater ponds collect runoff along the northern boundary of the plant property, and two smaller stormwater ponds are located in the southern portion of the property.

The Facility operates under a Multi-Sector Generic Permit for Stormwater Discharge Associated with Industrial Activity (Facility ID: FLR05H580) for the discharge of on-site stormwater to Turkey Creek through Outfalls 001 and 002. This permit must be renewed prior to expiration on October 2, 2018. The permit requires GREC to implement a Stormwater Pollution Prevention Plan (not provided for review) and routinely collect stormwater samples for analysis.

6.6 Solid Waste

Solid waste products generated by plant operation include bottom ash, fly ash, and ZLD solids. The bottom ash and ZLD solids do not have beneficial uses and are hauled to an off-site landfill. -Fly ash is currently utilized for beneficial reuse.

6.7 Hazardous Wastes

According to a 2014 Phase I Environmental Site Assessment of the plant property, the Plant is identified as a Resource Conservation and Recovery Act ("RCRA") Conditionally Exempt Small Quantity Generator of hazardous waste. At the time, the Phase I report was published, no hazardous wastes had been produced that required off-site disposal.

6.8 Spill Control and Response

The Facility operates according to a Spill Prevention, Control, and Countermeasure Plan, last updated in July 2017, which is designed to achieve compliance with 40 CFR Part 122 to reduce the potential for oil and fuel spills and improve the ability of facility personnel to handle accidental releases. The Facility also has an Emergency Response Plan, issued January 12, 2017, which establishes guidelines for responding to plant emergencies.

6.9 Phase I Environmental Site Assessment

A Phase I Environmental Site Assessment of the plant property was completed by Environmental Consulting & Technology, Inc. in March 2014. One Recognized Environmental Condition ("REC") was identified and is associated with groundwater contamination in the shallow aquifer beneath the site that has been impacted by the operation of the Deerhaven Generating Station, located east and adjacent to the Plant. Historical groundwater monitoring data shows exceedances for common metals, including iron. At the time, the Phase I report was published, no notices of violation or warning letters had been issued by the FDEP, which oversees compliance of the Deerhaven Generating Station.

Evidence of on-site underground storage tanks were not identified.

6.10 Storage Tanks

Storage tanks of regulated substances must be registered. GREC fuel storage facilities are located off-site and fuel will be transported to the site as needed.

6.11 Noise

A noise study was conducted and the results were submitted as part of the SCA. Background noise measurements were collected. Operational parameters were modeled to predict sound level at the property boundaries. The results showed all fenceline predictions (maximum predicted 53 decibels ("dBA")) and all predictions 200 feet beyond the fenceline (maximum predicted 51 dBA) meet requirements of the City of Gainesville ordinance which establishes maximum noise levels of 66 dBA (daytime) and 60 dBA (nighttime).

The Facility retrofitted the stack with an upgraded silencer. Measurements of pre- and post-installation demonstrate the silencer was effective at removing a significant amount of sound. The Facility appears to be in compliance with local regulation, but is always subject to complaint response.

6.12 Potential Future Regulatory Considerations

The conditions of compliance a facility is subject to may change as regulations evolve. Below are a few considerations for future regulatory compliance.

6.12.1 Future Air Quality Considerations

For future air quality threats, the EPA has traditionally tightened the air quality standards. For this facility, the pollutants of greatest concern would be the NO_2, ozone, and PM. Although today's air quality in the area around the Plant is currently in attainment, the tightening of the NAAQS could bring the area to non-attainment in the future. The traditional AQCS for non-attainment areas is to apply Reasonably Available Control Technology ("RACT"). Worst-case RACT controls for nitrogen dioxide ("NO_2"), ozone and $PM_{2.5}$ would be SCR for NOx and ozone, and a scrubber or DSI system, and an SCR and baghouse for particulate control. The Plant currently has all the controls that historically have satisfied worst-case RACT determinations. Therefore, there is a low likelihood that additional environmental controls for NAAQS will be required.

In addition to NAAQS, visibility and pollutant transport rules could be applicable in the future. Again, traditional controls for these programs would be similar to the worst-case RACT controls. The Facility currently has those AQCS. Some additional future issues could arise depending on the Plant's operating profile. AQCS are designed for specific operating conditions. For example, the SCR operates above a minimum operating temperature. If the gas temperature is not hot enough, insufficient NOx will be removed and the permit conditions may not be met. Based on discussions with GREC, the load at 60 MW and below would threaten NOx compliance. The other systems (baghouse and DSI) can likely operate well below 60 MW while meeting the permitted emission limits. For startup and shutdown conditions, the EPA could add additional requirements beyond the ones in the current permit. If that happened, NOx emissions would likely be the greatest at-risk pollutant. Additional studies would need to be performed to determine any potential add-on controls under this scenario, but it is possible a Selective Non-Catalytic Reduction (SNCR) may be required. In the unlikely event a SNCR system is added, the costs would not be expected to be extremely high (installed cost likely less than $5 million in 2017 dollars) if the existing infrastructure for an SCR already on site (i.e. ammonia storage) can be used. This price was based on a standard SNCR "rule of thumb" cost range of $15 to $20/kW. No engineering has been performed to develop this number. Additionally, the permit limits startup hours on a per startup basis and annual total. Plant operations may be limited based on how the Plant is dispatched or a relaxation of the startup hours may require additional controls such as an SNCR. MACT could become more stringent in the future. However, the existing controls appear to provide margin to the existing IB MACT emission rates.

Another potential concern, once GRU owns both facilities, is 1-hour SO_2 modeling. Because GREC did not have to model short-term SO_2 impacts, and the existing DGS was therefore not recently modeled, it is possible that modeled NAAQS exceedances could occur. One-hour SO_2 NAAQS has been exceeded by numerous new and existing power plants in modeling exercises. The FDEP could choose to model 1-hour SO2 to determine county designations per EPA criteria. There would not need to be any new project performed at either facility for both to be modeled. It is not anticipated that violations would occur, but this cannot be determined without actual modeling being performed.

6.12.2 Future Water Considerations

For future water issues, the Plant appears to be able to comply with future rules. The Facility is a ZLD site and has cooling towers. The water source is generally good quality groundwater with sufficient availability. Thus, significant water considerations are not expected to impact the Facility in the future.

6.12.3 Future Solid Waste Considerations

For solid waste issues, the biomass plant ash is not controlled under the coal combustion rule that applies to coal facilities. The ash is handled dry and either sold or landfilled. The ash is not hazardous waste so little future impacts are expected from the biomass ash.

6.12.4 Future General Considerations

Based on discussions with GREC, local groups have actively been involved with plant compliance and beyond. The Plant has incorporated noise and odor mitigation to satisfy the neighbors and has accepted additional emissions limits (furans) that were not required under current regulations. It is unknown what, if any, future issues may come from local groups. However, assuming the acquisition goes through, being adjacent to and part of the GRU coal plant may create complications and future liability risks. These risks cannot be quantified at this time, but looking at the GRU and GREC facilities as a whole may present unique and unintended challenges for either facility in the future.

6.13 Summary of Environmental Issues

Based on the information received, it appears that the Plant has applied for and received the appropriate permits. Further, based on the information provided via hardcopy and through the interview process, the

Plant appears to be operating in accordance with its permits. There is potential for future environmental permitting concerns once the DGC and GREC become one integrated facility; however, these potential future concerns are likely minor, and easily resolved.

7.0 CONCLUSIONS

7.1 Conclusions

Based on the information reviewed and the results of the Independent Engineer's Report, Burns & McDonnell concludes that the Plant appears to be designed and constructed in accordance with generally accepted industry standards. The Facility utilizes proven and reliable technologies and a similar configuration to other biomass-fueled resources. The Plant's capital costs, fixed O&M and variable O&M costs are within reasonable range for a unit of this size and technology. The Plant appears to have the appropriate contracts in place to support the Facility's operations. Burns & McDonnell believes that if the Plant is operated and maintained in accordance with good industry standards, the Plant should be fully capable of providing long-term, reliable service as an intermediate generation resource.

CREATE AMAZING.

Burns & McDonnell World Headquarters
9400 Ward Parkway
Kansas City, MO 64114
O 816-333-9400
F 816-333-3690
www.burnsmcd.com